ATTACHMENT A

SETTLEMENT AGREEMENTS

A.24-03-019

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

Dated: **June 30, 2025**

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

Table of Contents

Section	**Page**

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

Table of Contents (Continued)

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

Table of Contents (Continued)

Section	**Page**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

In accordance with Article 12 of the Rules of Practice and Procedure (Rules) of the California Public Utilities Commission (Commission or CPUC), the undersigned Settling Parties in Application (A.) 24-03-019, *Application of Southern California Edison Company to Establish Marginal Costs, Allocate Revenues, and Design Rates*, enter into this Marginal Cost and Revenue Allocation Settlement Agreement (Agreement or Settlement Agreement).

1. PARTIES

The Settling Parties to this Agreement are Southern California Edison Company (SCE); The Utility Reform Network (TURN); the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); Small Business Utility Advocates (SBUA); California Farm Bureau Federation (CFBF); California City-County Street Light Association (CALSLA); California Manufacturers & Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Producers and Users Coalition (EPUC); Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); and Walmart Inc. (referred to hereinafter collectively as Settling Parties or individually as Party).[1]

A. SCE is an investor-owned public utility and is subject to the jurisdiction of the CPUC with respect to providing electric service to its CPUC-jurisdictional retail customers.

[1] No parties oppose this Agreement. The remaining parties take no position on the Agreement: CALSTART, Inc. (CALSTART); California Community Choice Association (CalCCA); Center for Accessible Technology (CforAT); Electrify America, LLC; EVGo Services; Direct Access Customer Coalition (DACC); Vehicle-Grid Integration Council; Terawatt Infrastructure, Inc.; and the Western Manufactured Housing Communities Association (WMA). None of these parties served testimony on marginal cost and/or revenue allocation issues.

B. TURN is an independent, non-profit consumer advocacy organization that represents the interests of residential and small commercial utility customers.

C. Cal Advocates represents the interests of California's public utility customers. Its mission is to obtain the lowest possible rate for service consistent with safe, reliable service, and the State's environmental goals. Pursuant to California Public Utilities Code Section 309.5(a), Cal Advocates is directed to primarily consider the interests of residential and small commercial customers in revenue allocation and rate design matters.

D. SBUA represents the interests of small commercial customers of bundled electricity as defined in California Public Utility Code Section 1802.

E. CFBF is California's largest farm organization, working to protect family farms and ranches on behalf of its nearly 27,000 members statewide and as part of a nationwide network of more than 5.8 million members.

F. EUF is an *ad hoc* group that represents the interests of medium and large bundled service and Direct Access (DA) customers in California, with locations in investor-owned utility and/or municipal utility service areas, primarily taking service on rate schedules for accounts with demand above 100 kW.

G. CMTA represents more than 400 businesses from the entire manufacturing community -- an economic sector that generates approximately $300 billion annually and employs more than 1.2 million Californians, about 8% of state's total workforce and more than 12% gross state product.

H. CLECA is an organization of large, high voltage, high load factor industrial electric bundled service, CCA and DA customers located throughout the state. These companies are in the steel, cement, industrial and medical gas, beverage, minerals processing, cold storage, and pipeline transportation industries, and share the fact that electricity costs comprise a significant portion of their cost of production.

I. EPUC represents the end-use and customer generation interests of the following companies: California Resources Corporation, Chevron U.S.A. Inc., PBF Holding Company, Phillips 66 Company, and Tesoro Refining and Marketing Company LLC.

J. CALSLA represents all California cities and counties, with the primary purpose of educating and advocating positions on street light rates.

L. SEIA is the national trade association for the solar and storage industries. Through outreach and education, SEIA and its over 1,200 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy and storage.

M. Walmart Inc. is a multinational retail corporation that operates 303 retail units, 17 distribution centers, and four fulfillment centers and employs over 104,000 associates in California.

2. <u>DEFINITIONS</u>

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "BTUs" means British Thermal Units, which is commonly used as a measure of the energy capacity of natural gas.

B. "Base Services Charge" means the fixed customer charge applied to customers in the Domestic Rate Group, as differentiated for California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA), and Non-CARE/Non-FERA customers.

C. "Bundled service customers" means those customers who take retail electric generation service from SCE.

D. "CA" means Community Aggregator.

E. "California Climate Credit," sometimes referred to as the Climate Dividend, means the portion of greenhouse gas (GHG) auction revenues returned on a per-account basis to residential customers pursuant to D.12-12-033.[2]

F. "CAISO" means the California Independent System Operator.

---

[2] D.21-08-026 orders the IOUs to utilize a flat credit distribution method where qualifying small businesses receive a credit identical to the residential California Climate Credit at the same times the residential California Climate Credit is distributed. The change was implemented with the 2022 ERRA Forecast rates.

G. “Capacity Allocation Tool” provides a method for allocating annualized generation capacity marginal costs across hours of the year by determining a distribution of capacity shortfall events triggered by a scaled load forecast.

H. “Collars” mean the restrictions (employed at the initial revenue allocation stage only), on delivery and generation revenue changes both above and below the Functional SAPC, as described in Paragraph 4.B.2., below.

I. “CCA” means Community Choice Aggregator.

J. “Customer Charge” means the fixed charge applied to customers in rate groups other than the Domestic Rate Group. See Base Services Charge for Domestic Rate Group.

K. “DA” means Direct Access.

L. “Departing Load Customers” means those customers who take retail generation electric service from a provider other than SCE, and includes DA, CA, and CCA customers.

M. “DWR” means the California Department of Water Resources.

N. “EITE” means Emission-Intensive and Trade-Exposed customers, as those customers are defined in D.12-12-033. These customers receive GHG auction revenues pursuant to formulas adopted in D.14-12-037, as may be modified by the Commission.

O. “ERRA” means Energy Resource Recovery Account.

P. “FERC” means the Federal Energy Regulatory Commission.

Q. “Fixed Recovery Non-bypassable Charge” is a charge imposed on customers to pay the Recovery Bond principal, interest, and other related costs issued under Public Utilities Code § 850.1.

R. “Flexible Generation Capacity” (*i.e.*, “Flex”) refers to the portion of generation capacity required to meet system ramping needs.

S. “Functional SAPC” allocation or “Functional SAPC basis” means allocation of SCE’s revenue requirement to each of SCE’s rate groups based on the System Average Percent Change (SAPC) for the particular function, *e.g.*, distribution or generation.

T. "GHG allowance revenues" include the Greenhouse Gas (GHG) offsets, EITE and California Climate Credit.

U. "GHG costs" means the GHG costs ordered by the Commission to be collected in rates as a result of D.12-12-033.

V. "GHG offsets" means GHG allowance revenues used to offset delivery rates for small commercial and agricultural customers pursuant to D.12-12-033.

W. "Grid" when used in the context of distribution design demand marginal cost components, refers to the portion of distribution and subtransmission marginal costs that are not peak-related.

X. "Marginal Cost" means the change in total cost due to a small change in the quantity of an item produced or service provided.

Y. "NSGC" means New System Generation Charge, and is a cents per-kilowatt-hour charge included in SCE's delivery charges that recovers from all bundled service, CA, DA and CCA customers the revenues associated with facilities and resources that provide grid reliability for all electricity customers on its distribution system, as authorized by the Commission in D.09-03-031 and by SCE Advice Letter 2346-E (May 29, 2009).

Z. "NCO" means New Customer Only, and is a method used to derive marginal customer costs, taking into account the capital cost of adding new customers only and other O&M costs.

AA. "Non-Allocated Revenues" are revenues assigned directly to the rate groups that incur these costs, consisting primarily of Streetlight Rate Group facilities' costs and power factor revenues, and which are excluded from SCE's allocation of its revenue requirement to all other rate groups.

BB. "Peak," when used in the context of distribution design demand marginal cost components, refers to the portion of distribution marginal costs that is primarily sized to support the time-sensitive nature of coincident peak demand on the distribution system. "Peak," when used in the context of generation marginal cost components, refers to that portion of the marginal costs that is incurred to support the electric system during maximum system demand.

CC. "PCIA" means the Power Charge Indifference Adjustment and is a rate that is paid by departing load customers as a separate line item on their bills.

DD. "Primary Voltage" means the level of voltage at facilities at which electric power is taken or delivered, generally at a level between 12 kV and 33 kV, but always between 2 kV and 50 kV.

EE. "PPP" means Public Purpose Programs. PPP charges collect revenues for Commission-sponsored energy efficiency, renewable and research programs.

FF. "PUCRF" means Public Utilities Commission Reimbursement Fee.

GG. "RECC" or "Real Economic Carrying Charge," means a constant payment in real dollars that includes the recovery of the capital investment, earnings, taxes, and other capital carrying costs. The RECC when escalated at the rate of inflation over the life of the asset recovers the net present value of revenue requirement of a utility investment. It also represents the value of deferring a utility investment by a year.

HH. "RPS" means Renewables Portfolio Standard.

II. "Secondary Voltage" means the level of voltage at facilities at which electric power is taken or delivered, generally at a level between 120 volts and 480 volts, but always less than 2 kV.

JJ. "SGIP" means Self Generation Incentive Program, with cost allocation as modified by Resolution E-4926.

KK. "SAPC" means "System Average Percentage Change," and it is the percentage difference in the system average rate when comparing one total authorized revenue requirement to another total system authorized revenue requirement. Functional SAPC allocations will be implemented periodically when SCE's authorized revenue requirements change after the initial implementation of this Agreement.

LL. "SAR" or "System Average Rate" is the average cents per-kilowatt-hour rate that applies to SCE's bundled service customers, based on SCE's authorized revenue requirements and a forecast of the CPUC-approved forecast level of sales.

MM. "SCE's Model" means SCE's Marginal Cost and Revenue Allocation Model provided to the Settling Parties for settlement purposes on March 27, 2025, filename "2025 GRC Marginal Cost and Revenue Allocation Settlement.zip." Any rates reflected in SCE's Model are illustrative and will be refined in the individual rate design tracks.

NN. "Subtransmission Voltage" means the level of voltage at facilities at which electric power is taken or delivered, generally at a level greater than 50 kV and less than 220 kV.

OO. "TOU" means time-of-use. These are the time periods established for provision of electric service in which demand or energy charges may vary in relation to the time-related cost of service. Unless otherwise stipulated, TOU periods mean those that were adopted in D.18-07-006.

PP. "UMP" means a set of unit marginal costs that will be used where specific rate components are set at their marginal cost levels or developing rates based on marginal cost.

QQ. "Wildfire Fund Non-bypassable Charge" means the revenues collected by SCE to pay any bonds issued by DWR to fund the Wildfire Fund defined in Public Utilities Code Section 1701.8 and 3280 et seq.

3. RECITALS

A. Paragraph 4.B.7 of SCE's 2021 General Rate Case (GRC) MCRA Settlement Agreement, which was approved in D.22-08-001, applies to changes in SCE's authorized revenue requirements until a decision in this proceeding is implemented. SCE's rate groups are expected to receive revenue requirement changes that will be reflected in rates before this Agreement has been implemented. These revenue changes will have disparate impacts on each rate group based on the Functional SAPC allocation methodology and revenue allocators that apply to these revenue changes in accordance with D.22-08-001.

B. In Phase 2 of SCE's 2025 GRC, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each group.

C. On March 29, 2024, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in A.24-03-019.

D. On August 26, 2024, SCE filed its Amended Application and served amended versions of its initial prepared testimony and supplemental testimony regarding changes to 2025 GRC Phase 2 residential rate designs to include a fixed charge structure as adopted in D.24-05-028.

E. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a June 3, 2024 prehearing conference.

F. Cal Advocates served initial testimony on November 22, 2024 and amended testimony on December 27, 2024.

H. On January 8, 2025, the following parties submitted prepared testimony regarding marginal costs and/or revenue allocation: TURN, SBUA, CFBF, CALSLA, SEIA, CLECA, and EPUC.

I. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on January 16, 2025.

J. Continuing settlement discussions occurred among the parties after January 16, 2025.

K. On June 6, 2025, SCE provided notice to all parties pursuant to CPUC Rule of Practice and Procedure 12.1(b) of a settlement conference to review this Agreement. The settlement conference was held on June 13, 2025.

K. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to marginal costs and the rate group allocation of SCE's authorized revenue requirement beginning with the implementation of a CPUC decision approving this Agreement, and have reached agreement as indicated in Paragraph 4 of this Agreement.

L. Appendix A to this Agreement provides a comparison of the Settling Parties' positions, where applicable, related to marginal costs and revenue allocation that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and Appendix A, the terms of this Agreement shall control.

M. Appendix B provides illustrative class average rate summaries based on a consolidated SCE revenue requirement. Consistent with Paragraph 10 of this Settlement Agreement, these class average summaries are for illustrative purposes only and have no precedential value. The rate summaries will be adjusted to reflect

SCE's actual revenue requirements in accordance with the provisions of this Agreement when rates are first implemented pursuant to the provisions of this Agreement.

4. <u>AGREEMENT</u>

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Settlement Agreement. The terms of the Settlement Agreement are interrelated and together represent the result of negotiations and compromises by the Settling Parties. Nothing in this Settlement Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit or that its position has greater or lesser merit than the position taken by any other Settling Party. Nothing in this Settlement shall be deemed an endorsement by any Party of any individual term of this Settlement. This Agreement is subject to the express limitation on precedent described in Paragraph 10. Unless specifically stated otherwise herein, this Agreement and its terms are intended to remain in effect until a decision is implemented in Phase 2 of SCE's 2029 GRC. Accordingly, the Settling Parties respectfully request that the Commission approve each and every aspect of the Settlement Agreement without modification.

A. <u>Marginal Costs</u>

This Settlement Agreement does not reflect approval or acceptance of any of the Settling Parties' marginal cost proposals. The Settling Parties agree that it is reasonable to use the marginal costs set forth in this Paragraph 4.A and use collars as described in Paragraph 4.B.2 on the initial revenue allocation results. These marginal costs were used to form the foundation of the revenue allocation agreement and may also be used as the basis for initial (though not binding) rate designs in subsequent potential rate design settlement agreements. They are strictly non-precedential pursuant to Paragraph 10.

1) <u>Generation Marginal Energy Costs</u>

For purposes of revenue allocation and rate setting, the Generation marginal energy costs (MECs) are based on the nominal 2025 avoided energy costs specified in the

CPUC's 2024 Avoided Cost Calculator.[3] Table RA-1 below summarizes the MECs by season and TOU period.[4]

Table RA-1
Generation Marginal Energy Costs (2025$)

2025 Marginal Energy Costs							
		Summer			Winter		
Vintage	Annual	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Super-Off-Peak
¢/kWh	5.833	8.786	6.500	5.748	6.688	7.000	3.093

2) <u>**Generation Capacity Marginal Costs**</u>

For purposes of revenue allocation and rate setting, the Generation Capacity Marginal Cost (GCMC) shall be $132.72/kW-year. The Settling Parties agree to use SCE's Capacity Allocation Tool to spread the GCMC across TOU periods and that it be partly allocated based on peak demand and partly based on the need for ramping capacity, *i.e.*, flexible capacity. Table RA-2 outlines the GCMC for Peak and Ramp by season and TOU period.

Table RA-2
Generation Marginal Capacity Costs (2025$) By TOU Period

Marginal Capacity Cost Revenue							
	Summer			Winter			
	On	Mid	Off	Mid	Off	Super-Off	Total
Total Bundled Peak	90.63%	2.63%	6.52%	0.22%	0.00%	0.00%	100.00%
Total Bundled Ramp				100.00%			100.00%

Table RA-3 illustrates the derivation of Generation Capacity Marginal Cost Revenues using the agreed upon GCMC. The $132.72 GCMC value does not include a planning reserve margin adder.[5]

---

3 The CPUC's 2024 ACC was approved by Resolution E-5328.

4 The date and hours specified in the ACC reflect 2018 timestamps. The MECs by season and TOU period summarized in Table RA-1 include an adjustment that maps the hourly MECs to 2025 timestamps.

5 Exhibit SCE-02, SCE Testimony on Marginal Costs and Sales Forecast Proposals, p. 3.

Table RA-3
Generation Capacity Marginal Cost Revenue (Illustration)

Gen Capacity MW	
Peak	10,237
Ramp	6,779
Gen Capacity MC Revenues	
Peak	956,383,749
Ramp	633,276,814
Total	**1,589,660,563**

3) **Customer Marginal Costs**

For purposes of revenue allocation and rate setting, marginal customer costs are determined based on SCE's RECC marginal customer costs calculations. Actual agreed upon marginal cost values will be shown in each group's respective settlement track. The resulting marginal customer costs are listed in Table RA-4, below:

Table RA-4
Customer Marginal Costs
(2025$)

Customer Marginal Costs ($/Customer-Mo)		
Item	**Rate Group**	**$/Customer-Mo**
1	Domestic	$ 12.84
2	GS-1	$ 13.33
3	TC-1	$ 10.72
4	GS-2	$ 137.49
5	GS-3	$ 496.38
6	TOU-8 Secondary	$ 1,012.41
7	TOU-8 Primary	$ 118.72
8	TOU-8 Subtransmission	$ 1,688.84
9	AG <= 200	$ 36.59
10	AG > 200	$ 354.80
11	Streetlights	$ 8.89
	*Standby values are equal to their Non-Standby rquivalent listed above	

4) Distribution Capacity Marginal Costs

For the purposes of revenue allocation and rate setting, marginal distribution capacity costs shall be consistent with SCE's proposal,[6] which provides the results listed in Table RA-5 below. The table below indicates that approximately 62% of the non-ISO transmission design demand marginal costs are peak-capacity related, and 38% of the costs are grid related. The table below also indicates that approximately 33% of the distribution design demand marginal costs are peak-capacity related, and 67% are grid related.

6 Exhibit SCE-02, Marginal Cost and Sales Forecast Proposals.

Table RA-5
Functionalized Distribution Marginal Cost by Asset Category and Asset Type

Summary of Design Demand Marginal Costs ($/kW-Yr)			
Item	Description	Peak	Grid
	Non-ISO Transmission		
1	Circuit	0.00	17.93
2	Substation	29.01	0.00
	Distribution		
3	Circuit	26.73	89.88
4	Substation	16.98	0.00

B. Revenue Allocation

In order to avoid litigation, and to mitigate potentially adverse impacts on any particular rate group based on movement towards more cost-based rates in this proceeding, the Settling Parties agree to allocate SCE's total revenue requirement on an overall revenue-neutral basis. This Settlement Agreement is based on a number of assumptions as inputs to SCE's revenue allocation model. These assumptions were agreed upon by the Settling Parties for the sole purpose of reaching this Settlement Agreement.

The Settling Parties agree that the illustrative revenue allocation results set forth in Appendix B of this Agreement are reasonable. However, the level of SCE's authorized revenues and CPUC-approved forecasted sales at the time that this Agreement will be implemented are presently unknown. Thus, this Agreement reflects the use of a consolidated SCE revenue requirement of $17,466 million in October 2024, which includes revenues for transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, the Self-Generation Incentive Program (SGIP), Demand Response, the Wildfire Fund Non-bypassable Charge, Fixed Recovery Non-bypassable Charge, the New System Generation Charge (NSGC), and the GHG offsets.[7] The illustrative rate levels provided in Appendix B of this Agreement are based on this consolidated SCE revenue requirement and will be adjusted to reflect SCE's actual

[7] California Climate Credit and the revenues to be returned to EITE customers are included in the consolidated SCE revenue requirement as are PUCRF revenues. However, both are excluded during the revenue allocation and collaring process.

revenue requirements in accordance with the provisions of this Agreement when rates are implemented pursuant to the provisions of this Agreement.

1) Consolidated Revenue Requirement

As noted immediately above, the 2025 consolidated revenue requirement of $17,466 million is based on SCE's revenue requirement effective as of October 1, 2024.

Table RA-6 below provides additional details with respect to the assumed revenue requirements that are reflected in the 2024 consolidated revenue requirement.

Table RA-6
Consolidated Revenue Requirement Summary

	October 2024 Revenue Requirements ($000)		
	Total Retail	Bundled Service	Unbundled Service
Generation			
ERRA (Fuel & Purchased Power + GHG Cost)	$ 4,703,703	$ 4,703,703	$ -
PABA/ERRA Balancing Account	$ (74,095)	$ (74,095)	$ -
GRC Phase 1	$ 751,185	$ 751,185	$ -
Other PCIA/CTC	$ -	$ 210,243	$ (210,243)
Other Generation	$ 45,350	$ 45,350	$ -
New System Generation	$ 690,407	$ 463,718	$226,690
Distribution			
GRC - Distribution O&M & Capital (exclud. WF below)	$ 8,331,758	$ 5,836,152	$ 2,495,606
Vegetation Management Related	$ 563,598	$ 394,784	$ 168,814
GRC Track 2	$ 135,162	$ 94,677	$ 40,485
GRC Track 3	$ 135,416	$ 94,855	$ 40,561
Charge Ready/ Transportation Electrification	$ 58,355	$ 40,876	$ 17,479
CEMA	$ 425,371	$ 297,960	$ 127,411
Demand Response	$ 49,288	$ 34,525	$ 14,763
GHG Revenue	$ (955,105)	$ (685,819)	$ (269,286)
Other Distribution	$ 262,972	$ 184,204	$ 78,768
Nuclear Decommissioning	$ 6,885	$ 4,583	$ 2,302
Public Purpose Programs (PPP)			
Energy Efficiency	$ 464,341	$ 315,871	$ 148,470
CARE Administration	$ 9,103	$ 6,193	$ 2,911
Other PPP	$ 214,929	$ 146,207	$ 68,722
Transmission	$ 1,132,619	$ 786,196	$ 346,423
AB 1054 Securizitation (GSRP cap ex post Aug 1, 2019)	$ 19,257	$ 12,951	$ 6,305
AB 1054 Securizitation (Tracks 1 & 2 capex, Track 2 O&M)	$ 86,988	$ 58,505	$ 28,483
Wildfire Fund Non-Bypassable Charge	$ 408,912	$ 267,142	$ 141,769
Total Revenue Requirement	**$ 17,466,397**	**$13,989,965**	**$3,476,432**

A number of variables could either increase or decrease the revenue requirement when this Agreement is implemented and applied to SCE's authorized revenues. For bundled service customers, the consolidated revenue requirement in this Agreement represents a system average rate of 27.07¢/kWh (excluding the California Climate Credit and EITE revenue return), based upon SCE's forecasted sales for 2024. For departing load customers, the consolidated revenue requirement in this Agreement represents a system average rate of 14.19¢/kWh (excluding the California Climate Credit and EITE revenue return).

2) <u>Collars on Revenues Allocated to Rate Groups</u>

As a result of the revenue allocation methods and marginal costs applied to SCE's authorized revenue requirements, each rate group will receive different amounts of SCE's authorized revenue requirement relative to the change in the underlying functional allocation of revenues. To promote rate stability, the revenue allocations and illustrative rates agreed to by the Settling Parties employ restrictions on delivery and generation revenue changes both above and below the current class average rate levels.

Except where otherwise specified, any revenue amount that would constitute an under-collection or over-collection of SCE's authorized revenues from a particular rate group resulting from the collar restrictions specified in Parts (a) and (b) of Paragraph 4.B.2 will be allocated to the rate groups that have not reached the respective generation or distribution revenue collars. Table RA-7 and the subparts of Paragraph 4.B.2, below, describe these collars and illustrate the results.

Table RA-7
October 2024 Rates Compared to Capped Settlement Rates

	Retail Delivery Distribution Capping Direct Access and Bundled-Service Customers (Excludes Incremental WF Revenues)					Generation Capping Bundled-Service Customers (Includes Incremental WF Revenues)								
	Oct 2024 Retail Delivery Rate	Uncollared Retail Delivery Rate	Collared Retail Delivery Rate	Uncollared %	Collared %	Oct 2024 Total Rate	Uncollared Bundled Delivery Rate	Collared Bundled Delivery Rate	Uncollared Generation Rate	Uncollared Total Rate	Collared Generation Rate	Collared Total Rate	Uncollared %	Collared %
Residential	20.46	22.22	21.31	8.61%	4.19%	32.29	21.81	20.90	13.25	35.06	11.75	32.65	8.57%	1.13%
GS-1	17.08	16.61	16.94	-2.74%	-0.85%	27.29	15.14	15.46	9.02	24.15	11.38	26.84	-11.51%	-1.66%
TC-1	24.65	19.46	23.22	-21.08%	-5.81%	34.52	19.72	23.55	9.67	29.39	10.35	33.90	-14.86%	-1.80%
GS-2	18.86	16.88	17.76	-10.50%	-5.81%	30.88	18.02	18.98	9.21	27.23	11.34	30.33	-11.83%	-1.80%
TOU-GS-3	14.68	14.54	14.81	-0.96%	0.87%	24.81	15.28	15.56	8.98	24.26	9.45	25.02	-2.23%	0.83%
Total LSMP	17.26	16.14	16.73	-6.50%	-3.08%	28.36	16.57	17.20	9.10	25.67	10.84	28.03	-9.48%	-1.14%
TOU-8-Sec	13.21	12.64	12.87	-4.30%	-2.58%	22.55	13.06	13.30	8.96	22.02	9.43	22.73	-2.34%	0.79%
TOU-8-Pri	11.73	11.29	11.48	-3.74%	-2.12%	20.91	11.82	12.02	8.94	20.76	9.12	21.14	-0.71%	1.12%
TOU-8-Sub	5.27	5.25	5.27	-0.41%	0.04%	12.95	5.09	5.11	8.81	13.90	7.92	13.04	7.26%	0.63%
Total LP	10.31	9.96	10.10	-3.37%	-2.01%	19.36	10.45	10.61	8.88	19.33	8.91	19.53	-0.18%	0.85%
TOU-PA-2	15.32	12.62	14.43	-17.61%	-5.81%	24.98	12.56	14.37	9.47	22.03	10.16	24.54	-11.82%	-1.80%
TOU-PA-3	12.18	12.31	12.53	1.10%	2.87%	20.49	12.37	12.59	9.40	21.77	8.14	20.73	6.23%	1.13%
Total Ag.&Pumping	13.84	12.44	13.54	-10.17%	-2.22%	22.90	12.47	13.54	9.44	21.91	9.22	22.76	-4.31%	-0.58%
Total StLights	27.53	28.36	28.45	3.01%	3.35%	36.29	31.12	31.22	11.34	42.46	5.49	36.70	16.98%	1.13%
STANDBY/SEC	13.94	12.66	13.13	-9.21%	-5.81%	23.52	12.79	13.27	8.94	21.73	9.82	23.09	-7.59%	-1.80%
STANDBY/PRI	13.53	12.35	12.74	-8.73%	-5.81%	22.88	12.60	13.01	9.07	21.67	9.46	22.47	-5.27%	-1.80%
STANDBY/SUB	5.91	5.94	5.96	0.38%	0.86%	13.96	5.90	5.93	8.71	14.61	8.13	14.06	4.63%	0.68%
Total Standby	7.59	7.13	7.46	-6.14%	-1.74%	15.79	7.26	7.37	8.78	16.04	8.41	15.78	1.57%	-0.05%
System	16.12	16.15	16.15	0.19%	0.19%	27.03	16.55	16.56	10.51	27.07	10.51	27.07	0.15%	0.17%

Delivery Collar:	Limits
All rate groups: SAR + 4.0% cap	4.19%
All rate groups: SAR - 6.0% floor	-5.81%

Generation Collar:	Limits
All rate groups: SAR + 0.97% cap	1.13%
All rate groups: SAR - 1.97% floor	-1.80%

Notes:
Collar Limits are based on the System Average Rate delta, plus or minus the cap/floor percentages
Bundled Average Rates will no longer follow collar, because of the incremental WF revenues layered onto capped revenues

Table RA-8, below, lists the functional revenue allocator percentages that shall be used to allocate each unbundled revenue requirement to each rate group based on the above principles. For the Grid portion of distribution design demand marginal cost, distribution revenue allocators were initially derived, in part, from non-coincident peak values taken from a three-year average (2020-2022), as reflected in SCE's workpapers. For Schedules TOU-PA-2 and TOU-PA-3, the non-coincident peaks are based on a seven-year average of non-coincident peak demands spanning 2016-2022. This adjustment was made in order to encompass a broader range of potential hydrological conditions to be reflected in the billing determinants for agricultural and pumping customers, and the adjustment impacted the balance of distribution revenue allocators accordingly.

Table RA-8
GRC Revenue Allocation
Summary of Revenue Allocators
(Illustrative)

GRC Revenue Allocation
Summary of Revenue Allocators
(Illustrative)

	Distribution		Generation		APS & Interruptible Surcharge[1]	CSI[2]	SGIP[2]	PPP[3]	NDC/PUCRF[4]	NSGC[5]	Wildfire Special Allocator
	Uncollared	Collared	Uncollared	Collared							
Total Domestic	55.1%	50.2%	43.5%	38.6%	40.9%	34.5%	28.8%	40.2%	32.3%	43.9%	43.4%
GS-1	6.8%	7.1%	7.1%	9.0%	6.6%	8.3%	2.1%	7.6%	7.3%	7.4%	7.4%
TC-1	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
GS-2	15.8%	17.4%	14.2%	17.5%	15.0%	16.2%	14.0%	18.5%	16.7%	15.1%	17.9%
TOU-GS-3	7.7%	8.2%	7.9%	8.3%	8.8%	9.2%	12.4%	9.1%	10.0%	8.9%	8.8%
Total LSMP	30.4%	32.8%	29.3%	34.9%	30.4%	33.8%	28.5%	35.3%	34.1%	31.4%	34.2%
TOU-8-Sec	6.4%	6.9%	7.8%	8.2%	8.7%	9.1%	12.9%	8.2%	9.8%	8.3%	7.9%
TOU-8-Pri	4.1%	4.5%	5.1%	5.2%	6.5%	6.0%	9.3%	5.5%	7.2%	5.6%	5.5%
TOU-8-Sub	0.7%	1.4%	7.0%	6.6%	7.9%	8.5%	0.0%	3.8%	7.6%	6.6%	4.1%
Total Large Power	11.2%	12.9%	20.0%	20.0%	23.0%	23.7%	22.2%	17.5%	24.6%	20.5%	17.4%
TOU-PA-2	1.5%	2.0%	2.9%	3.1%	2.2%	3.2%	8.5%	2.3%	2.4%	1.7%	2.1%
TOU-PA-3	1.3%	1.4%	2.5%	2.2%	2.0%	2.8%	10.1%	1.7%	2.2%	1.5%	1.6%
Total Ag.&Pumping	2.9%	3.4%	5.4%	5.3%	4.2%	6.0%	18.6%	4.0%	4.6%	3.2%	3.8%
Total Street Lighting	0.2%	0.3%	0.7%	0.4%	0.6%	0.7%	0.0%	0.7%	0.6%	0.4%	0.6%
STANDBY/SEC	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.2%	0.2%	0.1%	0.1%
STANDBY/PRI	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	1.3%	0.6%	0.7%	0.2%	0.2%
STANDBY/SUB	0.1%	0.2%	0.8%	0.6%	0.6%	1.0%	0.5%	1.6%	3.0%	0.4%	0.3%
Total Standby	0.3%	0.4%	1.1%	0.9%	0.9%	1.3%	1.8%	2.3%	3.8%	0.6%	0.6%
Total System	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] APS and interruptible surcharge are allocated based on the marginal cost of generation revenue requirement for all retail sales

[2] SGIP revenues are allocated based on the proportion of incentives given to each rate groups

[3] PPP revenues are allocated to rate groups on a proportion of system revenues, with DA/CCA customers imputed as bundled customers

[4] NDC and PUCRF are allocated to all retail customers on an equal ¢/kWh basis

[5] NSGC is allocated to all retail customers based on the 12-CP allocators

DCARE surcharge is allocated on an equal c/kWh basis, excluding the DCARE and streetlight customers

Wildfire Fund Nonbypassable Charge is allocated on an equal c/kWh basis, excluding the DCARE customers

a) Delivery Service Collars for Allocated Revenues (Affects Departing Load and Bundled Service Customers)

For the delivery service collar, the Settling Parties agree to remove all GHG allowance revenues from the consolidated revenue requirement in Table RA-6. The Settling Parties agree to allocate delivery service revenues to the rate groups in accordance with the collared allocators shown in Table RA-8 above using a collar of the Functional SAR change for delivery services plus 4.0% and minus 6.%.

b) Generation Revenue Collars on Bundled Service Rates (Affects Bundled Service Customers Only)

For the generation revenue collar, the Settling Parties agree not to remove the GHG costs from the consolidated revenue requirement. The Settling Parties agree to allocate generation service revenues to bundled service customers in the rate groups in accordance with the collared allocators shown in Table RA-8 above, using a collar of the SAR change for (bundled) generation services plus 0.97% and minus 1.9%.

3) Establishment of Streetlight Rate Group Non-Allocated Revenues

For revenue allocation purposes, the Settling Parties agree that Non-Allocated Revenues specifically assigned to the Streetlight Rate Group shall be initially established at a level of approximately $89.99 million. The level of the Non-Allocated Revenues assigned to the Streetlight Rate Group in attrition years, including the split of the recovery of non-allocated revenues between street light facilities charges and distribution energy charges, shall be addressed in the rate design phase of this proceeding.

4) Allocation of CPUC and FERC-Authorized Revenue Requirements

The Settling Parties agree that all of SCE's CPUC- and FERC-jurisdictional revenue requirements as reflected in the consolidated revenue requirement shall be allocated as specified in Paragraph 4.B.5, below, to produce the allocation of revenues and corresponding rate levels for each rate group set forth in Appendix B. As provided in Paragraph 4.B.6, below, the consolidated revenue requirement shall be adjusted to reflect SCE's actual total system revenue requirement using SCE's Model, when rates based on this Agreement are implemented. Revenue changes and illustrative rates for both bundled service and departing load customers based on the consolidated revenue requirement are also shown in Appendix B.

5) Functional Revenue Requirements

SCE's authorized functional revenue requirements shall be allocated to rate groups as follows:

a) <u>FERC-Jurisdictional Transmission Revenue Requirement</u>

SCE's FERC-approved rate revenues shall be adjusted up or down in proportion to any change in FERC-authorized revenues. The applicable FERC-jurisdictional revenue requirement that is reflected in the consolidated revenue requirement shall be allocated to each rate group based on the 12 monthly system coincident peak (12-CP) revenue allocators shown in Table RA-8. FERC-jurisdictional rate components shall be added to the CPUC-jurisdictional delivery rates, resulting in total delivery service rates.

b) <u>Distribution-Related Revenue Requirement</u>

1) Subject to the collaring stages described in Paragraph 4.B.2 subpart a), above, as shown in Table RA-7, above, SCE's distribution revenue requirement reflected in the consolidated revenue requirement shown in Table RA-6 shall be allocated to rate groups based on the applicable distribution functional allocators shown in Table RA-8.
2) For purposes of revenue allocation, the revenue requirement resulting from interruptible rate program credits (*e.g.*, Base Interruptible Program, Summer Discount Plan (SDP), and Agricultural/Pumping-Interruptible), shall be based upon SCE's forecast of program participation and October 1, 2024 credit levels. These costs shall be allocated to rate groups for recovery in distribution rates from bundled service and departing load customers based on the system generation allocators shown in Table RA-8.
3) SCE will continue to recover Conservation Incentive Adjustment (CIA) balances from all customers, similar to other forecast-related imbalances, by recording any balance to the distribution sub-account of SCE's Base Revenue Requirement Balancing Account (BRRBA-D).
4) Non-Allocated Revenues shall be assigned directly to the rate groups responsible for incurring the costs. Paragraph 4.B.3,

above, specifies the level of Non-Allocated Revenues assigned to the Streetlight Rate Group.

5) The revenues associated with the discount provided to SCE's employees and retirees under Schedule DE shall be allocated to all other customers, except customers receiving the CARE discount, on an equal cents per-kilowatt-hour basis including all retail sales. The charge for the DE discount is reflected in the PPP charge.

c) SCE Generation Revenue Requirement

Subject to the collars described in Paragraph 4.B.2 subpart b), above, and as shown in Table RA-7, above, the generation revenue requirement reflected in the consolidated generation revenue requirement, net of contributions, e.g., PCIA from departing load customers, shall be allocated to rate groups based on the generation functional allocators shown in Table RA-8, above.

d) Wildfire Fund Non-bypassable Revenue Requirement

The Wildfire Fund Non-bypassable revenue requirement shall be recovered to support California's Wildfire Fund defined in Public Utilities Code Section 1701.8 and 3280 *et seq*., and authorized through D.20-09-023. The Wildfire Fund Non-bypassable charge is an equal cents per-kilowatt-hour charge assessed on all customer classes, excluding CARE customers and those customers who were exempt from the DWR Bond Charge.

e) Nuclear Decommissioning Revenue Requirement

In accordance with D.00-06-034, SCE's CPUC-jurisdictional, nuclear decommissioning revenue requirement shall be allocated to all rate groups, based on energy consumption reflecting total retail sales as indicated in Table RA-8, above, and shall be recovered on an equal cents per-kilowatt-hour charge designated in SCE's tariffs as the NDC.

f) Public Purpose Programs (PPP) Revenue Requirement

SCE's non-CARE PPP revenue requirement shall be allocated based on each rate group's percentage share of system revenues for bundled service and departing load customers with generation revenues for departing load customers imputed as if they were bundled service customers. The PPP revenue requirement allocated to each rate group in this manner shall be recovered from the customers of each respective rate group on a cent per-kilowatt-hour basis. CARE Balancing Account and CARE Administration revenues within PPP shall be allocated based on each rate group's percentage of revenues as stated above for PPP allocation, however the allocation factor for these two items is determined by excluding the associated CARE and Streetlight revenues, thereby exempting CARE and Streetlight customers from these two charges.

g) CARE Discount

The revenues associated with the discount provided to CARE customers shall be allocated to rate groups on an equal cents per-kilowatt-hour basis including departing load sales, but excluding the kWh usage of CARE and Streetlight customers. The CARE revenue requirement shall be recovered through a surcharge added to all customers' rates, excluding CARE customers themselves and customers in the Streetlight Rate Group. The CARE surcharge is reflected in the PPP charge.

h) SGIP Revenue Requirements

The SGIP revenue requirement reflected in the consolidated revenue requirement (Table RA-6) represents the authorized SGIP revenue on October 1, 2024. SGIP revenues are not expected to be recovered through rates upon implementation of the 2025 GRC Phase 2 rates. Pursuant to D.24-03-071, implementing Assembly Bill 209 and allocating $280 million of Greenhouse Gas Reduction Fund to the SGIP Residential Solar and Storage Equity Budget, SGIP revenues were removed from rates on January 1, 2025.

i) New System Generation Revenue Requirement

The NSG revenue requirement shall be allocated using the 12 monthly system coincident peak (12-CP) revenue allocators shown in Table RA-8.

j) Wildfire-Related Revenue Requirement

Wildfire-related Revenue Requirement (WRR) refers to existing and future Commission-authorized revenue requirements and fixed recovery charges that fall within the following categories: (1) wildfire-related costs authorized in GRC base rates,[8] including but not limited to costs tracked in the following accounts: Wildfire Risk Mitigation Balancing Account;[9] Vegetation Management Balancing Account;[10] and Risk Management Balancing Account;[11] (2) wildfire-related costs authorized in proceedings other than the GRC that review the reasonableness of the following accounts: Catastrophic Event Memorandum Account;[12] Wildfire Mitigation Plan Memorandum Account;[13] and other Commission-authorized balancing and memorandum accounts that may be established that include wildfire-related costs; and (3) wildfire-related costs that are authorized to be recovered through a Fixed Recovery Non-bypassable Charge. The WRR shall be recovered through distribution rates and shall be allocated using the formulaic approach described below.

---

[8] Wildfire-related costs authorized in the GRC include, but are not limited to, those costs identified in Section 4.1.7 of D.22-08-001. Such costs include, for example, capital expenditures for wildfire risk mitigation and wildfire-related O&M. "Capital expenditures for wildfire risk mitigation" refers to those utility distribution capital costs subject to Section 8386.3(e) of the Public Utilities Code, as well as other utility distribution infrastructure costs related to fire risk mitigation. "Wildfire-related O&M" refers to O&M expenses related to catastrophic wildfires.

[9] The two-way Wildfire Risk Mitigation Balancing Account (WRMBA) records the difference between the Wildfire Covered Conductor Program (WCCP) capital expenditures authorized in Track 1 of SCE's 2021 GRC D.21-08-036 and SCE's recorded (actual) WCCP capital expenditures. The capital-related revenue requirements for actual WCCP expenditures in excess of a 110% reasonableness threshold are subject to additional reasonableness review prior to recovery from customers.

[10] The two-way Vegetation Management Balancing Account (VMBA) records the difference between authorized O&M expenses adopted in D.21-08-036 for vegetation management activities and actual O&M expenses for vegetation management activities. Actual O&M expenses that exceed 115% of the authorized amount are subject to additional reasonableness review prior to recovery from customers. Wildfire-related costs tracked in the VMBA include, for example, wildfire vegetation management through SCE's Hazard Tree Management Program, and dead, dying and diseased tree removal.

[11] The one-way Risk Management Balancing Account (RMBA) records the difference between actual insurance premium expenses for wildfire liability coverage, including the costs of alternative risk transfer instruments, and the authorized insurance premium expenses for wildfire liability coverage adopted in D.21-08-036.

[12] The Catastrophic Event Memorandum Account (CEMA) includes, in pertinent part, incremental capital expenditures and O&M for restoration and/or repair of SCE's facilities as a result of a wildfire that is declared a disaster by a competent state or federal authority.

[13] The Wildfire Mitigation Plan Memorandum Account (WMPMA) includes, for example, incremental costs incurred to implement SCE's Wildfire Mitigation Plan (WMP) that are not otherwise covered in SCE's revenue requirements or tracked in another ratemaking account.

(1) WRR Allocation and Determination of Special Allocator Formula

The WRR shall be allocated using a composite weighted average allocator ("Special Allocator") for each customer class. The WRR will be allocated using a weighted average percent consisting of the distribution allocator and the system average percent (SAP) allocator,[14] respectively. The distribution allocation will represent 21.5%, with the SAP allocator representing 78.5% of the Special Allocator until changed in a subsequent GRC Phase 2.

(a) Special Allocator

The Special Allocator is a composite allocator that combines the distribution and SAP weights multiplied by the respective class allocators.

$\text{Special Allocator}_i = [(\text{Distribution Weight}*\text{Distribution Allocator}_i) + (\text{SAP Weight}*\text{SAP Allocator}_i)]/\text{WRR}$[15]

Below is an example intended only to provide an illustration of how the Special Allocator is developed:

1. Starting with a total annual WRR of $2,188 million as of October 2024.
2. The weighted average allocation associated with a WRR amount of $2,188 million for a given customer class is:

   $\$2{,}188 \text{ million}*[(21.5\% * \text{Distr. Allocator}_i) + (78.5\% * \text{SAP Allocator}_i)]$
3. The Special Allocator (%) for each customer class is the sum of the WRR Distribution Allocation Amount

---

14 The SAP allocator is based on each rate group's percentage share of system revenues for bundled service and departing load customers with generation revenues for departing load customers imputed as if they were bundled service customers.

15 Subscript "*i*" in the formula denotes the allocator assigned to each rate class.

and the WRR SAP Allocation Amount for that class divided by the total WRR, as shown in Table RA-8.

Once the Special Allocator is established for each class, it will also be used to allocate any additional WRR authorized for rate recovery during the attrition years. The Special Allocator will be adjusted annually during the attrition years to reflect adjustment in the distribution and SAP allocators and applied to the then-current amount of the total annual WRR. The average distribution and SAP allocators will be updated annually to reflect changes to the billing determinants (sales) and each class's percentage share of total system revenues. These updates will be input using the formulas above to derive the Special Allocator that will be used during each year.

(2) Securitized Wildfire-Related Revenue Requirements

- Wildfire-related revenue requirements subject to Recovery Bonds that are recovered through a Fixed Recovery Non-bypassable Charge[16] are considered part of the overall WRR that is considered during the development of the Special Allocator.
- The existing revenue allocation associated with wildfire-related securitization adopted in D.20-11-007, D.21-10-025, and D.23-02-023 shall be retained and unaffected by the Special Allocator.
- To retain the Special Allocator computed from the WRR allocation formula while also retaining the revenue allocation established for a securitized amount pursuant to its applicable Commission Financing Order, SCE shall establish each customer class's allocation of the non-securitized portion of the WRR such that the total weighted allocation for that class (*i.e.*, the

[16] Inclusive of Recovery Bond principal, interest, and related costs.

securitized allocation and the non-securitized allocation) conforms to the Special Allocator.

- For future wildfire-related securitizations, the Special Allocator shall be used to establish the allocation of the securitized amount. The Special Allocator effective at the time SCE files a request for authorization to issue Recovery Bonds will be used to establish a fixed allocation factor for the life of the bond,[17] with adjustment for sales changes as necessary to ensure collection of the necessary Commission-authorized revenue requirement.

6) Adjustments to Revenue Requirements When Agreement Is First Implemented

The revenues and rates reflected in Appendix B are illustrative and based on the consolidated revenue requirement of $17,466 million as described in Paragraph 4.B.1, above. To the extent SCE's actual authorized revenue requirement varies from this total when this Settlement Agreement is implemented, the following process will be used:

- Using the consolidated revenue requirement, SCE will adjust sales and demand to reflect SCE's forecast of sales and demand per billing period that is derived from the most recent approved ERRA forecast proceeding. During this process, SCE will use billing determinants derived from overall bundled service, CA, DA and CCA customer forecast sales, then run SCE's Model with the same input assumptions for marginal costs that were used to develop the allocation settlement including delivery and generation collaring, the allocation of generation revenue requirements, distribution revenue requirements, SGIP, WRR, and other revenue requirements that are reflected in this

[17] Revenue allocation between customer classes will ultimately differ from the Special Allocator due to CARE/FERA exemption for securitized revenues pursuant to Public Utilities Code Section 850.1. The CARE/FERA exempted revenues will be reallocated to the non-exempted classes in proportion to each respective class's contribution to the initially determined Special Allocator.

Agreement, and any updated FERC 12-CP transmission factors, if necessary.

- After removing Streetlight Rate Group Non-Allocated Revenues and other Non-Allocated Revenues, SCE will develop the revised collared functional revenue allocators; and
- To complete the revenue allocation process, SCE will apply the revised collared functional distribution and generation revenue allocators to the revised CPUC-authorized revenue requirements, add the Incremental Amount of the Wildfire-related Revenue Requirement, FERC-authorized revenue requirements per rate group, add the Streetlight Rate Group Non-Allocated Revenues back to the Streetlight Rate Group and add back other Non-Allocated Revenues so as to develop the portion of SCE's authorized revenue requirement that is allocated to each rate group.

7) **<u>Future Changes to SCE's Consolidated Revenue Requirement – Future Distribution and Generation Revenue Changes</u>**

The Settling Parties agree that distribution and generation revenue requirement changes occurring after the Commission has issued a decision in this proceeding and until Phase 2 of SCE's next GRC proceeding is implemented shall be allocated using the sales adjusted functional allocators used in this Agreement.

For consolidated rate changes resulting from revenue changes associated with SCE's ERRA(s) or GRC, SCE will adjust the rate levels for the base rate schedules, *e.g.*, Schedule TOU-D 4to9 or Schedule TOU-8-Sec-D, using a Functional SAPC adjustment. The four main steps to this adjustment are:

1. For ERRA-related revenue changes, SCE will update the forecasted billing determinants. For non-ERRA revenue changes, SCE will use the then-currently authorized forecasted billing determinants;
2. Using the billing determinants from Step 1 above, SCE will calculate the present rate revenues. SCE will then compare the

present rate revenues to the authorized rate revenues to determine the Functional SAPC adjustments (including various revenue adjustments such as for non-allocated revenue requirements, kVAR adjustments and GHG allowances, etc.);

3. For WRR, the Special Allocator will be adjusted annually during the annual implementation of SCE's ERRA Forecast proceeding to account for the then-current amount of the total annual WRR. The amount of annual WRR will be calculated and the weighted distribution and SAP allocators will be applied using the formulas as described in Paragraph 4.B.5 subpart j) above and reflecting the sales forecast adopted in the ERRA decision to arrive at the Special Allocator that will be used for the year;
4. The Functional SAPC adjustments from Step 2, above, will be applied to each rate component associated with that function. For example, the revised SCE generation revenue requirement resulting from SCE's ERRA proceedings will be allocated by applying a generation-level SAPC scalar based on the difference between present rate revenues and authorized rate revenues to the generation-related rate components for the default rate schedules; and
5. SCE will then rebalance optional rate levels to ensure revenue neutrality (for distribution and generation revenues) between the default rate schedule and the optional rate schedules on a functional basis using recorded (not forecast) billing determinants.[18]

---

[18] This calculation is performed by multiplying these billing determinants by the current rates. Adjustments to account for customers served on TOU-EV-8 & TOU-EV-9 rates will be made such that any revenue deficiency is contained within the individual rate class (*e.g.*, TOU-GS-2, TOU-GS-3, TOU-8) in which the deficiency exists.

C. Unit Marginal Prices

Separate from the set of unit marginal costs used for the purposes of revenue allocation and rate setting in this proceeding, the Settling Parties have agreed to adopt a set of unit marginal costs that will be used as Unit Marginal Prices (UMP) where specific rate components are set at their marginal cost levels for developing rates based on marginal cost, and for other pricing applications where GRC Phase 2 marginal cost values are used. Examples include generation hourly pricing for dynamic rates designed using a marginal cost price, where the settled UMP values for generation energy and capacity will be used; where the customer access charge associated with the Residential Base Services Charge is set at the marginal costs level, the UMP value for customer access will be used as the charge; for demand response program valuation, the UMP value for generation capacity will be used; and for SCE's Long-term Distribution Marginal Capacity Cost as used in the Commission's Avoided Cost Calculator (ACC), UMP values for UMPDD will set the foundation for avoided distribution costs. The aforementioned examples are not all-inclusive. The UMPs included here will be used in all rate-making proceedings where rates and pricing are designed based on marginal costs. Where applicable, the UMP values will be incorporated within a revenue neutral rate design inclusive of applicable non-bypassable charges. UMP values will be updated in each GRC Phase 2 cycle.

The following tables are the UMP values by function and by customer class where applicable.

Table RA-9
Generation Energy – UMPE Values ($/kWh

TOU Period	TOU Energy ($/kWh)
Summer On	0.08786
Summer Mid	0.06500
Summer Off	0.05748
Winter Mid	0.06688
Winter Off	0.07000
Winter Soff	0.03093

The underlying distribution of hourly marginal energy costs that are the basis for the TOU UMPE values shown in Table RA-9 above will be used in those applications where hourly

UMPE values are reflected in a given rate design. As an alternative, the CAISO hourly day-ahead market price for the UMPE value may be used.

Table RA-10
Generation Capacity – UMPGC Values ($/kW-yr.)

MGCC Element	MGCC Value ($/kW - Yr)
NetCONE	163.15
Effective Gen Cap	190.89
Peak	99.87
Ramp	99.87

The underlying distribution of hourly marginal generation capacity cost associated with the values shown in Table RA-10 above can be used in those applications where hourly UMPGC values are reflected in a given rate design.

Table RA-11
Distribution Design Demand – UMPDD Values ($/kW-yr.)

DDMC Element	DDMC Value ($/kW - Yr)	
	Grid	Peak
D - Circuits	94.42	28.08
D - Substations	-	25.27
S - Circuits	18.32	-
S - Substations	-	47.26

The underlying distribution of hourly marginal peak design demand cost associated with the values shown in Table RA-11 above can be used in those applications where hourly UMPDD values are reflected in a given rate design.

Table RA-12
Marginal Customer Access Costs – UMPCA Values ($/mo.)

Rate Group	MCAC ($/mo.)[2]
Domestic[1]	12.84
GS-1	13.33
Single Phase	11.35
Three Phase	16.25
TC-1	9.27
GS-2	65.29
Single Phase	17.89
Three Phase	72.81
GS-3	448.96
TOU-8-Sec	972.06
TOU-8-Pri	118.72
TOU-8-Sub	1,688.84
AG&P <= 200 KW	19.34
AG&P > 200 KW	342.77
Street Lights	5.05
STANDBY/SEC	972.06
STANDBY/PRI	118.72
STANDBY/SUB	1,688.84

1 The Domestic Effective Customer Charge of $19.13, reflects a weighted average of the CPUC approved basic service charges of $6 for CARE, $12.08 for FERA, & $24.15

2 For GS-2 and above, MCRA Settlement Rate Design Customer Marginal Cost includes 50kv transformer adjustment

5. IMPLEMENTATION OF SETTLEMENT AGREEMENT

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1, 2026.

6. INCORPORATION OF COMPLETE AGREEMENT

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties. Except as outlined in

Paragraph 8, if the Commission does not approve this Agreement in its entirety without modification, the terms and conditions reflected in this Agreement shall no longer apply to the Settling Parties.

7. SIGNATURE DATE

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

8. REGULATORY APPROVAL

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's 2025 GRC. The Settling Parties shall use their best efforts to obtain prompt Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall notify the other Settling Parties within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

9. COMPROMISE OF DISPUTED CLAIMS

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Settling Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

10. NON-PRECEDENTIAL

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before the Commission.

11. PREVIOUS COMMUNICATIONS

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to marginal cost and revenue allocation issues. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

12. NON-WAIVER

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

13. EFFECT OF SUBJECT HEADINGS

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

14. GOVERNING LAW

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

15. NUMBER OF ORIGINALS

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: June 30, 2025	SOUTHERN CALIFORNIA EDISON COMPANY */s/ Michael Backstrom* By: Michael Backstrom Title: Senior Vice President, Regulatory Affairs
Dated: June 30, 2025	THE UTILITY REFORM NETWORK */s/ David Cheng* By: David Cheng Title: Staff Attorney
Dated: June 30, 2025	SMALL BUSINESS UTILITY ADVOCATES */s/ Britt Marra* By: Britt Marra Title: Executive Director
Dated:	PUBLIC ADVOCATES OFFICE ______________________ By: Michael Campbell Title: Deputy Director
Dated: June 30, 2025	CALIFORNIA FARM BUREAU FEDERATION */s/ Kevin Johnston* By: Kevin Johnston Title: Director and Counsel
Dated: June 30, 2025	CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION */s/ Ronald Liebert* By: Ronald Liebert Title: Counsel
Dated: June 30, 2025	CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION */s/ Nora Sheriff* By: Nora Sheriff Title: Attorney

Dated: June __, 2025 SOUTHERN CALIFORNIA EDISON COMPANY

By: Michael Backstrom
Title: Senior Vice President, Regulatory Affairs

Dated: June _, 2025 THE UTILITY REFORM NETWORK

By: David Cheng
Title: Staff Attorney

Dated: June __, 2025 SMALL BUSINESS UTILITY ADVOCATES

By: Britt Marra
Title: Executive Director

Dated: June 30 2025 PUBLIC ADVOCATES OFFICE

By: Michael Campbell
Title: Deputy Director

Dated: June __, 2025 CALIFORNIA FARM BUREAU FEDERATION

By: Kevin Johnston
Title: Director and Counsel

Dated: June __, 2025 CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

By: Ronald Liebert
Title: Counsel

Dated: June__, 2025 CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: Nora Sheriff
Title: Attorney

Dated: June 30, 2025

ENERGY PRODUCERS AND USERS COALITION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Attorney

Dated: June 30, 2025

ENERGY USERS FORUM

/s/ Robert Kehrein

By: Robert Kehrein
Title: Executive Director

Dated: June 30, 2025

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

/s/ Daniel Denebeim

By: Daniel Denebeim
Title: Attorney

Dated: June 30, 2025

SOLAR ENERGY INDUSTRIES ASSOCIATION

/s/ Jeanne Armstrong

By: Jeanne Armstrong
Title: Senior Regulatory Counsel

Dated: June 30, 2025

WALMART INC.

/s/ Julie Clark

By: Julie Clark
Title: Attorney

Appendix A

Comparison of Party Positions and Settlement

Revenue Allocation

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	CALSLA	Settled Position
Capping / Collaring	Did not propose	Did not propose	Did not propose	Did not propose	Support cap (and floor) to the revenue allocation changes	Recommend that movement to cost of service accomplished over the 4-year rate case cycle at an avg change of not more than 2% per year, resulting in a max 4-year increase not greater than 8% of current revenues for any class.	Rate caps or collars may be needed under some circumstances	Propose rate collars of +/- 2% for delivery & +/- 1.5% for gen	Collaring: Delivery: 4%+/- 6%% Generation: 1%+/- 2%
Generation Revenues	Allocate to bundled service customers in each rate group based on marginal generation costs, after first being adjusted for expected CRS revenue from DA / CCA customers Generation Energy MCRR: 66% Generation Capacity MCRR: 34% Generation energy MCRR - determined by multiplying MECs by the forecasted TOU sales in each rate class, where the TOU sales are grouped in the	Proposes an "ALL Hours LOLE" approach. Allocates % cost to peak and % to flex to reflect a 4-hour lithium battery & a levelized over a 6-yr time horizon	Supports Cal Advocates use of a 4-hr battery storage	Doesn't agree with increase in Gen Energy marginal costs, which increases the gen revenue for non res classes	Recommends the net peak MCRR should be developed based on the entire MGCC as should the ramp MCRR without use of an "MGCC Factor". Recommend marginal gen cost revenues for bundled customers be: demand by class for top 100 net peak load hours x MGCC + kWh usage for each TOU period for each class x MEC for that time period x	Disagrees with Cal Advocates' proposal			Based on the generation functional allocators shown in Table RA-3, subject to collaring.

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	CALSLA	Settled Position
	proposed TOU periods Generation Capacity MCRR - Determined by multiplying marginal capacity costs by the forecasted peak and ramp MWs attributable to each rate class								
Distribution Revenues	Allocated to rate groups based on distribution marginal cost revenues Peak: PLRF Grid: NCP x EDF x Marginal Cost Customer: MC x Forecasted Customers Non-allocated revenues specifically assigned to street lights of $105,492,468	Adopt Cal Advocates' proposed rolling maximum load regression method (see DDMC below) and grid/peak split	Supports Cal Advocates proposal						Based on the distribution functional allocators shown in Table RA-3, subject to collaring Adjustment made for Ag & Pumping related to NCP demands to use a 7-yr average to account for broader range of potential hydrological conditions consistent with the 2021 GRC Phase 2 Settlement Agreement Non-allocated revenues assigned directly to street light of $89.99 million w/ recovery addressed in rate design phase of proceeding
Wildfire Allocation	Proposes to use allocation formula	Require SCE to allocate wildfire	Supports Cal		Supports SCE's proposal,	Supports SCE's proposal to	Costs should be allocated		The WRR shall be recovered through

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	CALSLA	Settled Position
	adopted in 2021 GRC Ph2 1. WF related costs authorized in GRC base rates 2. WF related costs authorized in non-GRC proceedings that review reasonableness of specific memo accounts 3. WF related costs that are authorized to be recovered through FRC	mitigation revenue based on an equal cents per kWh allocation	Advocates' proposal		however if approach is reopened, recommends costs be allocated on basis of marginal distribution costs	allocate wildfire mitigation cost and opposes Cal Advocates proposal	on basis of marginal distribution costs, but, supports SCE's proposal and opposes Cal Advocates proposal, as a means of settlement.		distribution rates and shall be allocated using the formulaic approach described above.
Public Purpose Programs	Maintain assignment of revenues to rate groups on a system average percentage (SAP) w/ generation revenues imputed for DA/CCA The CARE balancing account revenues are allocated to the other non-exempt rate groups based on each group's share of total annual energy sales (excluding the exempt groups)				Supports SCE proposal				Allocate based on each rate group's percentage share of system revenues for bundled service and DA/CCA customers, with generation revenues imputed for DA/CCA CARE discount allocated to rate groups on an equal cents per kWh basis, but excluding the kWh usage of CARE and street light customers CARE Balancing Account/CARE Admin shall be allocated based on each rate group's percentage of revenues as stated above for PPP

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	CALSLA	Settled Position
									allocation, excluding CARE and Streetlight revenues
Self-Generation Incentive Program	Allocate SGIP revenues based on the proportion of SGIP incentives disbursed to different rate groups over the most recent three years				Supports SCE proposal				Allocation is based on the proportion of incentives disbursed to each rate group over the most recent three years; update the allocation on a rolling basis annually
Tree Mortality Non-bypassable Charge	Set on a cent-per-kWh basis and added to PPP. Allocated using the 12-month CP allocator as adopted in D.18-12-003 & D.20-08-043				Supports SCE proposal				Set on a cent-per-kWh basis and added to PPP. Allocated using the 12-month CP allocator as adopted in D.18-12-003
Nuclear Decommissioning	Allocated on an equal cents / kWh basis to rate groups for all retail customers				Supports SCE proposal				Allocated on an equal cents / kWh basis to rate groups for all retail customers
Demand Response	Interruptible Programs – recovered from all rate groups in distribution rates; allocated to rate groups based on the marginal cost of generation methodology		Use EPMC generation w/ gen imputed for DA/CCA		Supports SCE proposal				Interruptible program costs shall be allocated to rate groups for recovery in distribution rates based on the system generation allocators DR rev req 50% of DR rev req will be allocated be each rate group's proportional share of system revenues, with generation

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	CALSLA	Settled Position
									revenues for DA/CCA customers imputed as bundled customers and the remaining 50% will be allocated by uncollared distribution allocators
CIA	Recover imbalances from all customers								SCE would recover the amount from all customers
Non-Allocated Streetlight (SL) Revenue Requirement	Set the non-allocated revenue requirement at $88.511 million for 2021, derived using the Results of Operations Model in SCE's GRC Phase 1, and is based on the forecast FERC Account 373 Rate Base and O&M expenses attributable to streetlight							Cap SL facilities charge increases at 5%	Use a non-allocated rev req of $89.99 million

Marginal Costs

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	SEIA	Settled Position
GCMCs ($/kW-yr. w/o RA adder)	$89.48 /kW-yr Forecast for the NetCONE of a 6-hour lithium-ion battery proxy resource, net of energy rents based upon 2025 forecast	$116.16/ kW-yr, fpr the NetCONE of a 4-hr lithium-ion battery & levelized over 6-yr period	Supports Cal Advocates proposal	Supports 6-hr lithium-ion battery as proxy resource. Recommends revising NETCONE methodology to include nuclear, natural gas, & hydroelectric power generation, not exclusively PV + storage.	$168.07 /kW-yr SCE's MGCC is understated as it is based on 2022 IRP. Recommends adjusting the ER assumption based on 2024 ACC SERVM avg price factor by yr thru 2050. Opposes Cal Adv's MGCC proposal (4hr battery) but agrees w/data source being 2023 IRP vs 2022 IRP. .	$325.35/ kW-yr. Disagrees with SCE's subtraction of the energy rents from the CONE to arrive at the NetCONE..		$136.62/ kW-yr Recommends MGCC based on the MGCC calculated in the 2024 ACC for yr 2025 -%160 per kW-yr.	$132.72 / kW-yr NetCONE
Peak / Flex Split of GCMCs	Peak/ Flex MCRR ratio 66%/34%, ratio. Allocation of peak capacity costs is based on the relevant top 100 hours of net loads. Allocation of flexible capacity cost is based on the relevant top 10 maximum daily 3-hour change in net load								Peak/ Flex MCRR ratio 66%/34%
MECs (₵/kWh)	Summer: On – 6.04 ¢/kWh Mid –4.99 ¢/kWh Off – 4.97 ¢/kWh Winter: Mid – 5.60 Off – 6.05 ¢/kWh SOff – 3.32 ¢/kWh	Recommends use of the CPUCs 2024 Strategic Energy Risk Valuation Model (SERVM) production cost model to forecast MECs. Recommends inclusion of RPS adder.			Recommends MECS be based on 2023 PSP. Supports Cal Advocates recommendation that 2024 SERVM model outputs should be used for MECs. Opposes Cal Adv's RPS Adder. Summer: On – 6.71 ¢/kWh			Supports Cal Advocates in recommending use of SERVM modeling of the 2023 PSP, but doesn't support adder. Summer: On – 9.33 ¢/kWh Mid –6.89 ¢/kWh	Summer: On – 8.79 ¢/kWh Mid – 6.50 ¢/kWh Off – 5.75 ¢/kWh Winter: Mid – 6.69 ¢/kWh Off – 7.00 ¢/kWh SOff – 3.09 ¢/kWh

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	SEIA	Settled Position
	Derived using production simulation model (PLEXOS)	Summer: On – 8.63 ¢/kWh Mid –9.71 ¢/kWh Off – 6.68 ¢/kWh Winter: Mid – 7.54 ¢/kWh Off – 7.82 ¢/kWh SOff – 4.31 ¢/kWh			Mid –7.72 ¢/kWh Off – 4.87 ¢/kWh Winter: Mid – 5.68 ¢/kWh Off – 5.94 ¢/kWh SOff – 2.64 ¢/kWh			Off – 6.09 ¢/kWh Winter: Mid – 7.09 ¢/kWh Off – 7.42 ¢/kWh SOff – 3.28 ¢/kWh	
Customer MC Method	SCE's RECC	Cal Advocates' NCO Actual new connection used to calculate growth rate, uniform growth rate for all nonresidential customers, includes a replacement cost adder and exclude uncollectible expenses		Recommends the CPUC reject Cal Advocates' proposal for MCAC & believes residential uncollectibles should be counted toward MCAC	SCE's RECC	SCE's RECC			SCE's RECC marginal customer costs calculations
DDMCs ($/kW-yr.)	Computed using the incremental cost of adding capacity from the NERA regression method; functionalized into *peak* and *grid*, and into asset *type* (substations and circuits) and asset *category* (dist and subtrans);	Proposes to use rolling maximum regional load approach, instead of planned capacity, as independent variable in the NERA regression Uses historic recorded load in its NERA regression			Supports SCE's regression approach			MDCCs for dist substations/circuit s should be increased by 7% & 29%, respectively	For purposes of revenue allocation, marginal distribution costs shall be consistent with SCE's proposal. See row above
Peak / Grid Split of DDMCs	Use PLRF method as basis of assigning a time-sensitive allocation of peak capacity-related costs and EDF	Supports SCE's proposal, but SCE should continue to improve cost tracking for subtrans circuits.			SCE should use the same threshold of its A-bank substation PLRFs as it uses for B-bank/pri circuits PLRFs.	Disagrees with SCE's proposal to change the PLRF threshold for Abanks from 90% to 73%	Recommend s the PLRF threshold for A-Bank facilities be established at 73% of	Recommends $272per-kW-yr, allocated at $117per-kW-yr (peak) & $154per-kW-yr grid.	Dist Circuits: Grid-94.42/Pk-28.08 Dist Sub: Pk-25.27 Sub Circuits: Grid-17.11 Sub Substations:

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	CFBF	SEIA	Settled Position
	method for grid-related costs. Propose to change the PLRF threshold for Abanks to 73% of the forecasted peak load from the 90% of the recorded peak load used in the 2021 GRC. Dist Circuits: Grid-94/Pk-28 Dist Sub: Pk-25 Sub Circuits: Grid-18 Sub Substations: Pk-47	Supports SCE's PLRF method. Dist Circuits: Grid-90/Pk-27 Dist Sub: Pk-16 Sub Circuits: Grid-18 Sub Substations: Pk-29 Recommends 100%peak costs of sub transmission circuits			Recommends adoption of A-bank substation PLRF based on a 73% PLL instead of a 73% substation pk load threshold. PLRF cost responsibility should be based on regional instead of centralized basis.		the PLL rather than 73% of the forecasted peak load		Pk-45.50
Sales Forecast	Use kWh sales forecast for 2024 as the basis for the billing determinant forecast and rate design proposals, as filed in A								Use SCE's 2024 sales forecast as of Oct 1, 2024

Appendix B

Illustrative Rates Using Revenue Allocation Inputs From Settlement Agreement

Table B-1
Bundled Service Rate Groups (without California Climate Credit and EITE Credits)
Illustrative Rates[1]

	October 2024	Uncapped Rates	Proposed Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	32.3	35.1	32.7	8.6%	1.1%	119%	121%
GS-1	27.3	24.2	26.8	-11.5%	-1.7%	101%	99%
TC-1	34.5	29.4	33.9	-14.9%	-1.8%	128%	125%
GS-2	30.9	27.2	30.3	-11.8%	-1.8%	114%	112%
TOU-GS-3	24.8	24.3	25.0	-2.2%	0.8%	92%	92%
Total LSMP	28.4	25.7	28.0	-9.5%	-1.1%	105%	104%
TOU-8-Sec	22.5	22.0	22.7	-2.3%	0.8%	83%	84%
TOU-8-Pri	20.9	20.8	21.1	-0.7%	1.1%	77%	78%
TOU-8-Sub	13.0	13.9	13.0	7.3%	0.6%	48%	48%
Total Large Power	19.4	19.4	19.5	0.0%	0.9%	72%	72%
TOU-PA-2	25.0	22.0	24.5	-11.8%	-1.8%	92%	91%
TOU-PA-3	20.5	21.8	20.7	6.2%	1.1%	76%	77%
Total Ag.&Pumping	22.9	21.9	22.8	-4.3%	-0.6%	85%	84%
Total Street Lighting	36.3	42.5	36.7	17.0%	1.1%	134%	136%
STANDBY/SEC	23.5	21.7	23.1	-7.6%	-1.8%	87%	85%
STANDBY/PRI	22.9	21.7	22.5	-5.3%	-1.8%	85%	83%
STANDBY/SUB	14.0	14.6	14.1	4.6%	0.7%	52%	52%
Total Standby	15.8	16.0	15.8	1.6%	-0.1%	58%	58%
Total System	27.0	27.1	27.1	0.2%	0.2%	100%	100%

Excludes Climate Dividend and EITE Credits

Table B-2
Direct Access Groups
Direct Access/CCA Rate Groups (without California Climate Credit and EITE Credits)[1]
Illustrative Rates

	October 2024	Uncapped Rates	Proposed Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	20.2	22.0	21.1	8.7%	4.2%	143%	149%
GS-1	14.3	13.8	14.2	-3.3%	-1.0%	101%	100%
TC-1	22.5	17.6	21.1	-21.9%	-6.0%	158%	149%
GS-2	15.5	13.9	14.6	-10.8%	-6.0%	109%	103%
TOU-GS-3	12.9	12.8	13.0	-0.9%	0.9%	91%	92%
Total LSMP	14.5	13.5	14.0	-6.7%	-3.1%	102%	99%
TOU-8-Sec	11.9	11.3	11.6	-4.5%	-2.7%	84%	81%
TOU-8-Pri	10.7	10.3	10.5	-3.8%	-2.2%	76%	74%
TOU-8-Sub	5.3	5.3	5.3	-0.5%	0.0%	37%	37%
Total Large Power	9.3	8.9	9.1	-3.5%	-2.0%	65%	64%
TOU-PA-2	14.0	11.4	13.1	-18.9%	-6.2%	99%	92%
TOU-PA-3	11.0	11.1	11.3	1.1%	3.0%	77%	80%
Total Ag.&Pumping	12.5	11.2	12.2	-10.0%	-2.1%	88%	86%
Total Street Lighting	17.8	16.7	16.8	-5.9%	-5.5%	125%	118%
STANDBY/SEC	13.2	11.8	12.2	-11.2%	-7.8%	93%	86%
STANDBY/PRI	12.2	11.1	11.4	-9.4%	-6.5%	86%	81%
STANDBY/SUB	6.2	6.0	6.0	-4.2%	-3.7%	44%	42%
Total Standby	8.0	7.5	7.6	-6.7%	-5.1%	56%	53%
Total System	14.2	14.2	14.2	0.1%	0.0%	100%	100%

[1] Excludes Climate Dividends, and EITE Credits

Table B-3
Proposed Bundled Service Revenues
Adjusted Consolidated Revenue Requirement ($MM)
(Illustrative)

	Transmission	Distribution	Other	Total Delivery	Generation	Total Bundled
Total Domestic	350.6	2,965.2	624.8	3,940.6	2,165.6	6,106.1
GS-1	62.2	471.3	150.0	683.6	504.6	1,188.2
TC-1	0.4	7.9	1.3	9.6	4.2	13.8
GS-2	135.2	1,222.4	293.3	1,650.9	981.9	2,632.8
TOU-GS-3	64.3	536.2	159.5	760.0	464.7	1,224.6
Total LSMP	262.1	2,237.8	604.1	3,104.0	1,955.4	5,059.4
TOU-8-Sec	56.4	432.3	152.4	641.1	454.4	1,095.5
TOU-8-Pri	32.1	229.7	89.2	351.0	267.7	618.7
TOU-8-Sub	26.4	44.6	87.3	158.4	241.8	400.2
Total Large Power	115.0	706.6	328.9	1,150.5	964.0	2,114.5
TOU-PA-2	16.5	174.0	56.3	246.9	174.5	421.4
TOU-PA-3	13.8	124.9	47.6	186.3	121.4	307.7
Total Ag.&Pumping	30.3	299.0	103.9	433.2	295.9	729.1
Total Street Lighting	3.3	102.2	7.8	113.3	19.9	133.3
STANDBY/SEC	1.4	9.9	2.9	14.2	10.6	24.7
STANDBY/PRI	4.4	35.6	10.6	50.6	37.1	87.7
STANDBY/SUB	19.1	49.9	43.8	112.8	160.8	273.6
Total Standby	24.9	95.4	57.3	177.6	208.5	386.1
Total System	**786.2**	**6,406.1**	**1,726.8**	**8,919.2**	**5,609.3**	**14,528.4**

Includes NSGS in "Other" Category

Table B-4
Proposed DA/CCA Service Revenues
Adjusted Consolidated Revenue Requirement ($MM)
(Illustrative)

	Transmission	Distribution	Other	Total Delivery	PCIA, CTC, DWRPC	Total DA
Total Domestic	142.5	1,410.7	119.6	1,672.8	(92.8)	1,580.0
GS-1	20.0	174.8	21.5	216.3	(14.7)	201.5
TC-1	0.1	2.6	0.2	3.0	(0.1)	2.8
GS-2	54.8	598.6	75.8	729.3	(41.5)	687.8
TOU-GS-3	33.3	347.2	46.3	426.8	(18.1)	408.7
Total LSMP	108.1	1,123.3	143.9	1,375.3	(74.5)	1,300.9
TOU-8-Sec	31.6	294.4	43.3	369.3	(19.1)	350.2
TOU-8-Pri	26.3	242.9	38.7	307.9	(11.5)	296.4
TOU-8-Sub	27.1	104.9	32.4	164.5	(4.9)	159.6
Total Large Power	85.0	642.2	114.5	841.6	(35.4)	806.2
TOU-PA-2	2.2	27.8	4.0	34.1	(2.4)	31.6
TOU-PA-3	2.1	23.8	4.0	29.9	(2.1)	27.8
Total Ag.&Pumping	4.3	51.7	8.0	64.0	(4.6)	59.4
Total Street Lightin	0.9	15.0	1.5	17.4	(1.2)	16.2
STANDBY/SEC	0.4	3.8	0.5	4.8	(0.2)	4.6
STANDBY/PRI	1.2	12.4	1.9	15.5	(0.7)	14.9
STANDBY/SUB	3.9	17.3	4.6	25.8	(0.7)	25.1
Total Standby	5.6	33.5	7.1	46.1	(1.5)	44.5
Total System	**346.4**	**3,276.3**	**394.6**	**4,017.3**	**(210.0)**	**3,807.3**

Includes NSGS in "Other" Category

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

AMENDED STREETLIGHT AND TRAFFIC CONTROL RATE GROUP SETTLEMENT AGREEMENT

Dated: **November 20, 2025**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

AMENDED STREETLIGHT AND TRAFFIC CONTROL RATE GROUP SETTLEMENT AGREEMENT

This Amended Streetlight and Traffic Control Rate Group Settlement Agreement ("Amended Settlement Agreement," or "Amended Agreement") is entered into by and among Southern California Edison Company ("SCE") and the California City-County Street Light Association ("CALSLA") (collectively referred to hereinafter as "Settling Parties").

1. PARTIES

A. SCE is an investor-owned utility ("IOU") and is subject to the jurisdiction of the California Public Utilities Commission (Commission or "CPUC") with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. CALSLA represents all streetlight and traffic control customers in California, with the primary purpose of educating and advocating positions on streetlight rates.

2. DEFINITIONS

When used in initial capitalization in this Amended Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Amended Agreement:

A. "October 2024 Consolidated Revenue Requirement" shall be as it is defined in Paragraph 4.B.(1) of the Marginal Cost and Revenue Allocation Settlement Agreement.

B. "Allocated Revenues" mean the amount of SCE's authorized revenue requirement that is allocated to the Streetlight and Traffic Control Rate Group. Allocated Revenues are used to establish the Energy Charges and the Customer Charges applicable to the Streetlight and Traffic Control Rate Group.

C. "Commission" or "CPUC" means the California Public Utilities Commission.

D. "Customer Charges" mean the fixed dollar-per-month charges applicable to certain Streetlight Rate Group and Traffic Control rate schedules.

E. "Energy Charges" mean the dollar per kilowatt-hour (kWh) charges applicable to Streetlight Rate Group and Traffic Control Rate Group rate schedules. Energy Charges recover SCE's costs for delivery services, generation, public policy and DWR revenue requirements.

F. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change (SAPC) for the particular function, *e.g.*, generation, or distribution and customer costs. In addition, this would include adjustments of FERC-jurisdictional transmission revenues as authorized by formula rates or otherwise.

G. "Legacy" refers to the treatment the Commission has prescribed for eligible solar customers as set forth in Decisions (D.)17-01-006 and D.17-10-018.

H. "Marginal Cost and Revenue Allocation Settlement Agreement" refers to the settlement of the same name filed in this proceeding on June 30, 2025.

I. "Non-Allocated Revenues" are revenues assigned directly to the rate groups that incur these costs. As used in this Amended Agreement, Non-Allocated Revenues are established in Paragraph 4.B. to be a combination of streetlight facilities' costs and distribution energy costs.

J. "Non-Energy Charges" mean the distribution charges applicable to street and area lighting, expressed as dollars per lamp per month. Non-Energy Charges are synonymous with "service charges," and "other charges" applicable to street and area lighting. They include facilities charges and operations and maintenance (O&M) charges.

K. "Shortfall" means the balance of the revenues resulting from the subtraction of the facilities charge revenues from the then-current Non-Allocated Revenues. The Shortfall is to be collected via distribution energy charges.

L. "Streetlight Agency" means a city, county or other entity that serves as the customer of record on a streetlight service account.

M. “Streetlight Rate Group” means the following SCE rate schedules: Schedule LS-1 Lighting—Street and Highway Company-Owned System—Unmetered Service; Schedule LS-2 Lighting—Street and Highway Customer-Owned Installation—Unmetered Service; Schedule LS-3 Lighting—Street and Highway Customer-Owned Installation—Metered Service; Schedule OL-1 Outdoor Area Lighting Service—Unmetered Service; Schedule AL-2 Outdoor Area Lighting Service—Metered; and Schedule TC-1 -Traffic Control Service.

N. “Transfer Entities” are cities, counties, or other entity that purchased their streetlight facilities from SCE.[1]

O. “TOU” periods mean time-of-use. These are the time periods established for the provision of electric service in which demand charges or energy charges may vary in relation to the cost of service.

P. “Unmetered Rate Schedules” means those rate schedules that are provided Unmetered Service as listed in Definition M.

3. <u>RECITALS</u>

A. In Phase 2 of SCE’s 2025 GRC, the Commission allocates SCE’s authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

B. On March 29, 2024, SCE filed its 2025 GRC Phase 2 application (Application A.24-03-019) and served supporting testimony regarding marginal costs, revenue allocation and rate design.

C. Protests and responses to SCE’s Application were filed on May 8, 2024. No party submitted a protest relating to SCE’s streetlight rate design proposals.

D. On August 26, 2024, SCE filed its Amended Application and served amended supporting testimonies as well as supplemental testimony.

E. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a June 3, 2024 prehearing conference. On June 12, 2024, CALSLA filed a Motion Requesting Party Status identifying numerous streetlight rate structure issues as among the nonresidential rate design issues to be resolved in the

[1] SCE did not sell distribution pole-mounted streetlights to any city.

proceeding. The Motion was granted by the Assigned Administrative Law Judge via Email Ruling on June 18, 2024.

F. On January 8, 2025, CALSLA served its initial testimony on streetlight rate design and revenue allocation issues.

G. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on January 16, 2025. Continuing settlement discussions occurred among the parties after January 16, 2025.

H. On June 6, 2025, SCE provided notice to all parties pursuant to CPUC Rule of Practice and Procedure 12.1(b) of a settlement conference to review this Amended Agreement. That settlement conference took place on June 13, 2025.

I. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to streetlight and traffic control rates beginning with the implementation of a CPUC decision approving this Amended Agreement, and have reached agreement as indicated in Paragraph 4 of this Amended Agreement.

J. Appendix A to this Amended Agreement provides a comparison of the Settling Parties' positions, where applicable, related to streetlight and traffic control rates that have been resolved by this Amended Agreement. In the event of a conflict between the terms of this Amended Agreement and Appendix A, the terms of this Amended Agreement shall control.

K. Appendix B provides illustrative streetlight and traffic control rates based on the 2025 Consolidated Revenue Requirement. These rates are for illustrative purposes only and have no precedential value.

4. <u>AMENDED AGREEMENT</u>

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Amended Settlement Agreement. Nothing in this Amended Settlement Agreement shall be deemed to constitute an admission by any party that its position on any issue lacks merit or that its position has greater or lesser merit than the position taken by any other Party. This Amended Settlement Agreement is subject to the express limitation on precedent described in Paragraph 10. Unless specifically stated otherwise herein, this Amended Agreement and its terms are intended to remain in effect from the date rate changes are implemented as a result of a Commission decision in this proceeding until a decision is implemented in Phase 2 of SCE's next GRC.[2]

A. Illustrative Rates

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Amended Agreement are reasonable. These rates are based on the October 1, 2024 Consolidated Estimated Revenue Requirement of $17,466 million described in more detail in Paragraph 4.B(1) of the Marginal Cost and Revenue Allocation Settlement Agreement. The Customer Charges and Energy Charges shall be adjusted to reflect SCE's actual authorized revenue requirement when this Amended Agreement is first implemented consistent with the treatment of Allocated Revenues adopted in this proceeding.

B. Non-Allocated Revenues

1) Initial and Subsequent Setting of Non-Allocated Revenues

A. Consistent with Paragraph 4.B(3) of the Marginal Cost and Revenue Allocation Settlement Agreement, Non-Allocated Revenues specifically assigned to the Streetlight rate group shall be established initially at a level of $89.99 million.

B. Upon initial implementation of this Amended Agreement, SCE will hold the non-allocated revenue requirement at the agreed upon level, but increase by 5% the facilities charges (in streetlight rate schedules that have facilities charges), and shall collect the Shortfall via distribution Energy Charges. Because facilities charges are collected only through unmetered rate schedules, the Shortfall shall be collected through the distribution energy charges in the Unmetered Rate Schedules.

[2] This Agreement supersedes and supplants the Streetlight and Traffic Control Rate Group Settlement Agreement adopted by the Commission in D.22-08-001 ("2021 Streetlight Agreement"). Except as otherwise specified, any obligation from the 2018 Settlement Agreement not explicitly re-stated here shall not survive.

C. During each of the attrition years, the streetlight lamp counts and associated sales in kWh will be updated accordingly to reflect the latest forecast. Should the facilities charges increase as a result of lamp and sales forecast adjustments, the increases shall be capped at 5% during attrition years, with the shortfall between the amount of the updated revenue requirement and revenues collected through capped facilities charges being rolled into the distribution energy rates.

2) **Relationship Between Non-Allocated Revenues and Distribution Allocation in the Revenue Allocation Settlement Agreement**

A. Notwithstanding any provision in this Amended Settlement Agreement, changes to the Non-Allocated Revenues resulting from the process described in Paragraph 4.B(1), above, shall not modify the distribution allocation reflected in the Marginal Cost and Revenue Allocation Settlement Agreement.

C. **Rate Design and Allocation of Revenues Among Streetlight and Traffic Control Rate Schedules**

1) **Rate Structures**

The rate structures of existing (as of October 1, 2024) streetlight and traffic control rate schedules, consisting of Customer Charges, Energy Charges and Non-Energy Charges, shall be maintained for all applicable Streetlight and Traffic Control Rate Group schedules.

2) **Customer Charges**

Upon initial implementation of this Amended Agreement, the Customer Charges for Schedule LS-3, Series Service shall be set equal to $434.84 per month. Schedule LS-3, Multiple Service and Schedules AL-2 and AL-2-F shall be set at the full EPMC level. For Schedule TC-1, the Customer Charge shall be set based on the method described in Paragraph 4.I. Thereafter, these

Customer Charges shall be adjusted on a Functional SAPC Allocation basis. The illustrative Customer Charges in Appendix B are as shown in Table 4-1 below:

Table 4-1

Illustrative Customer Charges[3]

Schedule	Customer Charge (per month)
LS-3, Series Service	$434.84
LS-3, Multiple Service	$12.00
AL-2	$12.00
AL-2-A	$12.00
TC-1	$25.88

3) Energy Charges

Proposed illustrative Energy Charges are based on the October 2024 consolidated revenue requirement, as set forth in Exhibit B. When this Amended Agreement is first implemented, these estimated Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the Marginal Cost and Revenue Allocation Settlement Agreement. Thereafter, these estimated Energy Charges shall be adjusted consistent with Paragraph 4.C(3) of the Marginal Cost and Revenue Allocation Settlement Agreement when SCE's authorized revenues change. Notwithstanding the foregoing, Energy Charges for unmetered service shall be consistent with the method set forth in Paragraph 4.B(1) of this Amended Agreement.

a) Generation-Related Energy Charges

Generation-related Energy Charges shall be established based on the marginal energy costs set forth in the Revenue Allocation Settlement Agreement. However, for

[3] Customers served on Schedules LS-1 and LS-2 do not pay a Customer Charge. For these customers, fixed costs are recovered in non-generation-related Energy Charges.

Schedule AL-2 (Legacy option), which has TOU components, the on-peak Energy Charges shall be set consistent with the Schedule TOU-GS-1-A Legacy Energy Charges.[4]

b) Non-Generation-Related Energy Charges

Non-generation-related Energy Charges that are designed to recover revenues associated with customer charges (for Schedule LS-1, LS-2, and OL-1 customers only), transmission, distribution, public purpose programs, new system generation service, nuclear decommissioning, CARE balancing account, Wildfire Fund Nonbypassable Charge, Fixed Recovery Charge, and the CPUC reimbursement fee[5] shall be established on the basis of the specified functional authorized revenue requirements and the terms specified in the Revenue Allocation Settlement Agreement. However, for Schedule AL-2 (Legacy option), which has TOU components, the on-peak Energy Charges shall be set consistent with the Schedule TOU-GS-1-A Legacy Energy Charges.[6]

4) Allocation of Revenues

A. The initial facilities charges for the different lamp options are shown in Appendix B (as "other charges"). The distribution Energy Charges for unmetered service will be adjusted to maintain the then-current Non-Allocated Revenues as described in Paragraph 4.B.

B. After this Amended Agreement is implemented, any changes to the Allocated Revenues that are collected through Energy Charges and Customer Charges for the Streetlight and Traffic Control Rate Group shall be implemented on a Functional SAPC Allocation basis whenever a change to SCE's authorized revenues are implemented in rates, using the then-current forecast lamp count and the applicable kWh consumption per lamp.

---

[4] Legacy AL-2 and TOU-GS-1-A rate schedules will migrate off Legacy rates in October through December of 2027.

[5] The charges that comprise the total energy charge can change from time-to-time as the CPUC authorizes new charges to be recovered though energy rates, or as charges reach the end their collection period.

[6] Legacy TOU-GS-1-A rate schedules will migrate off Legacy rates in October through December of 2027.

D. Schedules LS-1 and LS-2

There shall be no structural changes to Schedules LS-1 and LS-2.

As part of LS-1 Option E conversions communication process, SCE currently produces a rate analysis showing the rate comparison of the conversion. SCE will continue to include the updated comparison tool adopted in the 2021 GRC Phase 2 proceeding.

E. Schedule LS-3

There shall be no structural changes to Schedules LS-3.

- Schedule LS-3 will continue to be a non-time-variant rate structure with monthly limits on the allowable amount of daytime usage. See Paragraph 4.G, below.
- All provisions of the current Schedule LS-3 not explicitly revised herein shall survive and remain unchanged.

F. Schedule AL-2

1) Option AL-2-F (Flat Rate, Non-Legacy)

- Schedule AL-2-F will continue to be applicable to all non-Legacy customers who meet the eligibility requirements for Schedule AL-2.
- Schedule AL-2-F will continue to offer non-time-variant rate structures with monthly limits on the allowable amount of daytime usage. See Paragraph 4.G, below.

2) Option AL-2 (Legacy Rate)

- Off-peak energy charges shall be set consistent with Schedule AL-2-F (by function).
- Summer and winter on-peak Energy Charges shall be based on the Legacy Schedule TOU-GS-1-A summer and winter on-peak charges (by function).

G. Daytime Usage Limitations on Schedule LS-3 and AL-2

SCE shall continue to measure kWh usage to attempt to discern whether accounts served on Schedules LS-3 and AL-2 incur usage predominately for nighttime lighting. On a rolling 12-month basis, SCE will compare all usage incurred on an account between the hours of 8 a.m. to 4 p.m. during the preceding 12 months to the account's total usage for the preceding 12 months. If the usage during the hours of 8 a.m. to 4 p.m. exceeds 30% of the account's total usage incurred, the account will become ineligible prospectively for service under Schedule AL-2 or LS-3 and will, at SCE's sole discretion unless the customer affirmatively and timely elects otherwise, be placed as soon as practicable on an applicable general service schedule. For accounts with fewer than 12 months of historical usage data, where SCE determines that the usage incurred during the available months exceeds or in SCE's opinion is likely to exceed 30% of the total annual load, the accounts will become ineligible for service under Schedules AL-2 or LS-3 and will be placed on an applicable general service schedule.

H. Schedule OL-1

There shall be no changes to Schedule OL-1.

I. Schedule TC-1

Schedule TC-1 shall continue to consist of a monthly Customer Charge and a flat Energy Charge, as illustrated in Appendix B. SCE shall maintain the relationship between fixed and volumetric revenue recovery that was adopted by the Commission in the 2018 and 2021 GRC Phase 2 Streetlight Settlement Agreements, as updated to account for differences in marginal costs between the GRCs, such that approximately 73% of revenue is recovered through volumetric charges and 27% through fixed charges. After this Amended Agreement is implemented, changes to Energy Charges and Customer Charges for Schedule TC-1 shall be implemented on a Functional SAPC Allocation basis whenever changes to SCE's authorized revenues are implemented in rates, using the then-current forecast number of service accounts and the applicable kWh consumption per lamp.

Additionally, Settling Parties agree to address an operational issue related to adding safety-related devices—such as streetlights, flashing beacons, pedestrian crosswalk lights, and cameras—to traffic signal poles. These additions create only incidental and low-load impacts; however, SCE's tariff language does not explicitly allow for such configurations. In order to address this matter, Settling Parties agree to clarify the TC-1 tariff to explicitly allow for incidental safety-related devices to be installed on traffic signal poles. This revision will permit SCE to meter and bill these devices under Schedule TC-1, ensuring compliance and supporting public safety infrastructure without materially impacting rates or revenue. Incorporating this proposal provides a practical and collaborative path forward for municipalities and SCE.

J. Schedule WTR (Wireless Technology Rate)

Ancillary devices like Wi-Fi hotspots, traffic sensors, and cameras co-located on un-metered streetlight poles (e.g. LS-1, LS-2, and OL-1) not already served by metered streetlight, area lighting, or traffic lighting service are primarily low wattage. SCE will continue to exempt these low wattage ancillary devices from paying the monthly inspection charge. The intent of the monthly inspection charge is to appropriately charge for service in those applications where the average monthly usage is based on the size of fuse used in the connection equipment. The monthly inspection charge is primarily used for telecommunication devices.

K. Schedule Wi-Fi-1

No structural changes to Schedule Wi-fi-1 shall be made as a result of this Amended Settlement Agreement.

L. Distribution Pole-Mounted Rate Option

1. SCE shall continue to offer a rate option within Schedules LS-1 and OL-1 for distribution pole-mounted streetlights that will include lamp charges based on the difference between the net-plant-in-service value of a standard configuration streetlight asset, and the net-plant-in-service value of a standard configuration streetlight asset that removes the pole cost entirely. This method is described in Exhibit SCE-04.
2. Accounts taking service on the distribution pole-mounted rate option will receive a credit offsetting the facilities charge equal to $4.97/lamp.

3. This rate option will be offered to both Transfer and non-Transfer Entities. Customers must affirmatively elect to take service on this optional rate consistent with SCE's Tariff Rule 12.

M. Dimmable Streetlight Pilot

Settling parties agree that a dimmable streetlight rate option will not be offered at this time.

5. IMPLEMENTATION OF AMENDED SETTLEMENT AGREEMENT

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Amended Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Amended Settlement Agreement, but no earlier than June 1, 2026.

6. INCORPORATION OF COMPLETE AGREEMENT

This Amended Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of this Amended Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Amended Agreement not agreed to by all Settling Parties. Except as outlined in Paragraph 8, if the Commission does not approve this Amended Agreement without modification, then the terms and conditions reflected in this Amended Agreement shall no longer apply to the Settling Parties.

7. SIGNATURE DATE

This Amended Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

8. REGULATORY APPROVAL

A. The Settling Parties, by signing this Amended Agreement, acknowledge that they support Commission approval of this Amended Agreement and subsequent implementation of all the provisions of the Amended Agreement for the duration of rates implemented pursuant to a Commission order adopting this Amended Agreement in this proceeding, *i.e*., Phase 2 of SCE's 2025 GRC. The Settling Parties shall use their best efforts to obtain prompt Commission approval of the Amended Agreement. The Settling Parties shall jointly request that the Commission approve the Amended Agreement without change, and find the Amended Agreement to be reasonable, consistent with law and in the public interest.

B. Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Amended Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Party within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Amended Agreement through prompt written notice to the other Settling Parties.

9. COMPROMISE OF DISPUTED CLAIMS

This Amended Settlement Agreement represents a compromise of disputed claims between the Settling Parties after arm's-length negotiations. The Settling Parties have reached this Amended Settlement Agreement after taking into account the possibility that each Settling Party may or may not prevail on any given issue. The Settling Parties assert that this Amended Settlement Agreement is reasonable, consistent with law and in the public interest.

10. NON-PRECEDENT

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Amended Settlement Agreement is not precedential in any other pending or future proceeding before the Commission, except as expressly provided in this Amended Settlement Agreement or unless the Commission expressly provides otherwise.

11. PREVIOUS COMMUNICATIONS

The Amended Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to the resolution of streetlight and traffic control light issues. In the event there is any conflict between the terms and scope of this Amended Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Amended Settlement Agreement, the Amended Settlement Agreement shall govern.

12. NON-WAIVER

None of the provisions of this Amended Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing signed by that Settling Party. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Amended Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

13. EFFECT OF SUBJECT HEADINGS

Subject headings in this Amended Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

14. GOVERNING LAW

This Amended Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California, notwithstanding otherwise applicable conflict of law principles. The Settling Parties agree that the Commission retains jurisdiction to enforce the terms of this Amended Settlement Agreement and resolve any disputes regarding the Settling Parties' performance under the Amended Settlement Agreement.

15. NUMBER OF ORIGINALS

This Amended Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: November 20, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Daniel Hopper

By: Daniel Hopper
Title: Managing Director, Regulatory Policy

Dated: November 20, 2025

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

/s/ Daniel Denebeim

By: Daniel Denebeim
Title: Attorney for CALSLA

Appendix A

Comparison of Party Positions and Settlement

Comparison of Parties' Positions
Street and Area Lighting Rate Design Issues

	Current Treatment (i.e., 2021 GRC Outcome)	SCE	CALSLA	2025 GRC Settled Position
Non-Allocated Streetlight (SL) Revenue Requirement	Use a non-allocated rev req of $77.87 million	Set the non-allocated revenue requirement at $105.5 million for 2024, derived using the Results of Operations Model in SCE's GRC Phase 1, and is based on the forecast FERC Account 373 Rate Base and O&M expenses attributable to streetlight		Use a non-allocated rev req of $89.99 million
Facilities Charges	Increase facilities charges by a one-time adjustment of 5% upon implementation of SCE's 2021 GRC Phase 2 and recover the shortfall in distribution energy charges in the unmetered rate schedules. The facilities charges increase shall be capped at 5% during attrition years, with the shortfall between the amount of then updated revenue requirement and revenues collected through capped facilities charges be rolled into the distribution energy rates.	The monthly lamp facilities charges will be set to increase by 20% over the current rate level, with the shortfall recovered through distribution energy charges from non-metered streetlight rate schedules. The shortfall is measured by the difference between the non-allocated revenue requirement and the revenues recovered through the monthly facilities charges. Proposes to cap any further increases of the facilities charge at 5% during attrition years.	Streetlight facilities charge increases should be capped at 5% following both the final decision in this rate case and following adjustments to the streetlight non-allocated revenue requirement in the attrition years.	Increase facilities charges by a one-time adjustment of 5% upon implementation of SCE's 2025 GRC Phase 2 and recover the Shortfall in distribution energy charges in the unmetered rate schedules The facilities charges increase shall be capped at 5% during attrition years, with the shortfall between the amount of then updated revenue requirement and revenues collected through capped facilities charges be rolled into the distribution energy rates.
Energy Charges	Initially set energy charges residually after non-energy charges are computed (including implementation of the non-allocated rev reg agreement) using marginal costs and usage characteristics	Revise energy charges based on marginal costs and the usage characteristics of Streetlight customers. Set residually after first establishing streetlight non-energy charges.	Recommends continuing to set energy charges residually after the non-energy charges have been computed	Initially set energy charges residually after non-energy charges are computed (including implementation of the non-allocated rev req agreement) using marginal costs and usage characteristics

	Current Treatment (i.e., 2021 GRC Outcome)	SCE	CALSLA	2025 GRC Settled Position
Customer Charges	AL-2/LS-3: Use SCE's EPMC scaled RECC marginal customer access costs. • AL-2: $9.75/mo. • LS-3: $9.75/mo. • TC-1: customer charge is set to recover 27% of allocated revenue from the customer charge $21.60/mo.	AL-2/LS-3: Use SCE's EPMC scaled RECC marginal customer access costs. $8.25/mo. TC-1: collect a maximum of 27% of allocated revenue from the customer charge $22/mo.	CALSLA finds SCE's proposal of customer charge for AL-2/LS-3 ($8.25/mo.) reasonable. CALSLA finds SCE's proposal for a $22/mo. per month customer charge for traffic controls (TC-1) to be reasonable and proposes that the traffic control customer charge reflect 27% of the TC-1 revenue recovery based on whichever revenue allocation/marginal costs proposal the Commission approves.	AL-2/LS-3: Use SCE's RECC Method AL-2: $12.00/mo. LS-3: $12.00/mo. TC-1: use SCE's maximum 27% proposal
AL-2 / LS-3 Rates	Maintain the non-time-variant rate structure for LS-3 and AL-2-F with monthly limits on the allowable amount of on-peak usage. The Legacy time-of-use AL-2 option will continue to be available for eligible solar customers	Maintain the non-time-variant rate structure for LS-3 and AL-2-F with monthly limits on the allowable amount of on-peak usage. The Legacy time-of-use AL-2 option will continue to be available for eligible solar customers and will be migrated off Legacy rates in October 2027.	Uncontested	Maintain the non-time-variant rate structure for LS-3 and AL-2-F with monthly limits on the allowable amount of on-peak usage. The Legacy time-of-use AL-2 option will continue to be available for eligible solar customers until customers are migrated off Legacy rates in October 2027.
TC-1 Rate	Maintain the structure for TC-1	Maintain the structure for TC-1	N/A	Clarify and expand the TC-1 tariff to allow for incidental safety-related devices to be installed on traffic signal poles.
Distribution Pole Mounted Rate Option for	Adjust streetlight shared distribution pole discount to $4.10 per lamp per month	SCE will continue to offer a rate option for lamps mounted on SCE's distribution poles, as compared to those that are mounted on poles that support	CALSLA does not oppose SCE's proposal to adjust the streetlight shared distribution pole discount from $4.10 to $5.41 per month.	Adjust streetlight shared distribution pole discount to $4.97 per lamp per month

	Current Treatment (i.e., 2021 GRC Outcome)	SCE	CALSLA	2025 GRC Settled Position
Schedules LS-1 and OL-1		only streetlights. Customers taking service on this rate option are provided a credit of $5.41/lamp to the standard configuration charge for each distribution pole-mounted configuration.		
Dimmable Streetlight Rate	Conduct a two-phase pilot open to existing LS-1 customers with smart sensors deployed and four LS-2 customers. Phase 1: SCE will internally evaluate dimmable streetlight hardware and begin building standard interface/structure for customer billing Phase 2: SCE will test and refine interface for data integration, billing, and outage identification. Additionally, SCE will host meet and confers with interested parties and conduct an audit and/or create report evaluating pilot performance.	SCE's Dimmable Pilot Study concluded that since there is still significant work needed to integrate the data into various operational or metering systems, SCE will not implement any rate options to support this technology at this time.	Does not oppose SCE's decision to not further pursue additional dimmable streetlight pilots or a dimmable streetlight rate. Dimmable streetlight technology should be further evaluated for inclusion in future generations of advanced metered technology.	SCE will not implement any rate options to support dimmable technology at this time.
Ancillary Device Rate	Review WTR billing arrangement to determine if it is more appropriate to assess the monthly customer charge on a per device basis.	Proposes to maintain the customer charge on a per Customer Account basis.	Uncontested	Maintain the customer charge on a per Customer Account basis.

Appendix B

Illustrative Streetlight and Traffic Control Rates

	October 2024 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
AL-2-F									
Energy Charge - $/kWh	0.07209	0.06514	0.13723	0.07869	0.05625	0.13494	9.2%	-13.6%	-1.7%
Customer Charge - $/month	16.49	0.00	16.49	12.00	0.00	12.00	-27.2%		-27.2%
AL-2									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.39596	0.15897	0.55493	0.31293	0.14956	0.46249	-21.0%	-5.9%	-16.7%
Off-Peak	0.07209	0.06514	0.13723	0.07869	0.05625	0.13494	9.2%	-13.6%	-1.7%
Winter Season									
On-Peak	0.11777	0.10551	0.22328	0.10495	0.10478	0.20973	-10.9%	-0.7%	-6.1%
Off-Peak	0.07209	0.06514	0.13723	0.07869	0.05625	0.13494	9.2%	-13.6%	-1.7%
Customer Charge - $/month	16.49	0.00	16.49	12.00	0.00	12.00	-27.2%		-27.2%
DWL									
Energy Charge - $/kWh	0.13339	0.06504	0.19843	0.13659	0.05510	0.19169	2.4%	-15.3%	-3.4%
Rate A - Other Charges									
High Pressure Sodium Vapor Lamp - $/lamp/month									
50 Watt	10.35	0.00	10.35	10.87	0.00	10.87	5.0%		5.0%
70 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
100 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
150 Watt	10.84	0.00	10.84	11.38	0.00	11.38	5.0%		5.0%
Metal Halide Lamp - $/lamp/month									
100 Watt			0.00						
175 Watt			0.00						
Mercury Vapor Lamp - $/lamp/month									
75 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
HPSV Recommened (LED) - $/lamp/month									
50 Watt	10.27	0.00	10.27	10.78	0.00	10.78	5.0%		5.0%
70 Watt	10.27	0.00	10.27	10.78	0.00	10.78	5.0%		5.0%
100 Watt	10.35	0.00	10.35	10.87	0.00	10.87	5.0%		5.0%
150 Watt	10.94	0.00	10.94	11.49	0.00	11.49	5.0%		5.0%
Rate B - Other Charges									
High Pressure Sodium Vapor Lamp - $/lamp/month									
50 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
70 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
100 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
150 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
Metal Halide Lamp - $/lamp/month									
100 Watt			0.00						
175 Watt			0.00						
Mercury Vapor Lamp - $/lamp/month									
75 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
HPSV Recommened (LED) - $/lamp/month									
50 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
70 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
100 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
150 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
DWL (Continued)									
Rate C - Other Charges									
High Pressure Sodium Vapor Lamp - $/lamp/month									
50 Watt	0.32	0.00	0.32	0.34	0.00	0.34	6.3%		6.3%
70 Watt	0.32	0.00	0.32	0.34	0.00	0.34	6.3%		6.3%
100 Watt	0.32	0.00	0.32	0.34	0.00	0.34	6.3%		6.3%
150 Watt	0.32	0.00	0.32	0.34	0.00	0.34	6.3%		6.3%
Metal Halide Lamp - $/lamp/month									
100 Watt			0.00						
175 Watt			0.00						
Mercury Vapor Lamp - $/lamp/month									
75 Watt	0.37	0.00	0.37	0.39	0.00	0.39	5.4%		5.4%
Minimum Charge - $/month									
Rate A	100.00	0.00	100.00	100.00	0.00	100.00	0.0%		0.0%
Rate B	50.00	0.00	50.00	50.00	0.00	50.00	0.0%		0.0%

	October 2024 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
LS-1									
Energy Charge - $/kWh									
All Night Service	0.13339	0.06504	0.19843	0.13659	0.05510	0.19169	2.4%	-15.3%	-3.4%
Midnight Service	0.13339	0.06504	0.19843	0.13659	0.05510	0.19169	2.4%	-15.3%	-3.4%
Other Charges - All Night/Midnight Service									
Incandescent Lamps - $/lamp/month									
103 Watt	11.17	0.00	11.17	11.73	0.00	11.73	5.0%		5.0%
202 Watt	11.12	0.00	11.12	11.68	0.00	11.68	5.0%		5.0%
327 Watt	11.12	0.00	11.12	11.68	0.00	11.68	5.0%		5.0%
448 Watt			0.00						
Mercury Vapor Lamps - $/lamp/month									
100 Watt	10.62	0.00	10.62	11.15	0.00	11.15	5.0%		5.0%
175 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
250 Watt	10.89	0.00	10.89	11.43	0.00	11.43	5.0%		5.0%
400 Watt	11.23	0.00	11.23	11.79	0.00	11.79	5.0%		5.0%
700 Watt	11.17	0.00	11.17	11.73	0.00	11.73	5.0%		5.0%
1,000 Watt			0.00						
High Pressure Sodium Vapor Lamps - $/lamp/month									
50 Watt	10.35	0.00	10.35	10.87	0.00	10.87	5.0%		5.0%
70 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
100 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
150 Watt	10.84	0.00	10.84	11.38	0.00	11.38	5.0%		5.0%
200 Watt	11.22	0.00	11.22	11.78	0.00	11.78	5.0%		5.0%
250 Watt	11.29	0.00	11.29	11.85	0.00	11.85	5.0%		5.0%
310 Watt	11.29	0.00	11.29	11.85	0.00	11.85	5.0%		5.0%
400 Watt	11.22	0.00	11.22	11.78	0.00	11.78	5.0%		5.0%
Low Pressure Sodium Vapor Lamps - $/lamp/month									
35 Watt	12.62	0.00	12.62	13.25	0.00	13.25	5.0%		5.0%
55 Watt	12.62	0.00	12.62	13.25	0.00	13.25	5.0%		5.0%
90 Watt	13.32	0.00	13.32	13.99	0.00	13.99	5.0%		5.0%
135 Watt	13.42	0.00	13.42	14.09	0.00	14.09	5.0%		5.0%
180 Watt	13.44	0.00	13.44	14.11	0.00	14.11	5.0%		5.0%
LS-1 (Continued)									
Other Charges - All Night/Midnight Service									
Metal Halide Lamps - $/lamp/month									
75 Watt			0.00						
100 Watt	11.69	0.00	11.69	12.27	0.00	12.27	5.0%		5.0%
150 Watt	11.46	0.00	11.46	12.03	0.00	12.03	5.0%		5.0%
175 Watt	11.65	0.00	11.65	12.23	0.00	12.23	5.0%		5.0%
250 Watt	11.43	0.00	11.43	12.00	0.00	12.00	5.0%		5.0%
400 Watt	11.80	0.00	11.80	12.39	0.00	12.39	5.0%		5.0%
1,000 Watt			0.00						
1,500 Watt			0.00						
Light Emitting Diode (LED) Lamps (High Pressure Sodium Vapor Recommended Lamps) - $/lamp/month									
50 Watt	10.27	0.00	10.27	10.78	0.00	10.78	5.0%		5.0%
70 Watt	10.27	0.00	10.27	10.78	0.00	10.78	5.0%		5.0%
100 Watt	10.35	0.00	10.35	10.87	0.00	10.87	5.0%		5.0%
150 Watt	10.94	0.00	10.94	11.49	0.00	11.49	5.0%		5.0%
200 Watt	11.34	0.00	11.34	11.91	0.00	11.91	5.0%		5.0%
250 Watt	11.65	0.00	11.65	12.23	0.00	12.23	5.0%		5.0%
310 Watt	12.57	0.00	12.57	13.20	0.00	13.20	5.0%		5.0%
400 Watt	12.80	0.00	12.80	13.44	0.00	13.44	5.0%		5.0%
LS-1 (Option E)									
AB 719 Light Emitting Diode (LED) Lamps - $/Lamp/Month (High Pressure Sodium Vapor Recommended Lamps)									
50 Watt	11.69	0.00	11.69	12.58	0.00	12.58	7.6%		7.6%
70 Watt	11.75	0.00	11.75	12.62	0.00	12.62	7.4%		7.4%
100 Watt	11.90	0.00	11.90	12.74	0.00	12.74	7.0%		7.0%
150 Watt	12.61	0.00	12.61	13.53	0.00	13.53	7.3%		7.3%
200 Watt	13.27	0.00	13.27	14.34	0.00	14.34	8.0%		8.0%
250 Watt	13.91	0.00	13.91	14.81	0.00	14.81	6.4%		6.4%
310 Watt	15.28	0.00	15.28	15.98	0.00	15.98	4.5%		4.5%
400 Watt	15.68	0.00	15.68	16.41	0.00	16.41	4.7%		4.7%
Distribution Pole Mounted Discount									
$/lamp/month	(4.12)	0.00	(4.12)	(4.97)	0.00	(4.97)	20.6%		20.6%
Tap Device Annual Charge									
$/device	15.45	0.00	15.45	16.22	0.00	16.22	5.0%		5.0%

	October 2024 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
LS-2									
Energy Charge - $/kWh									
All Night Service	0.13339	0.06504	0.19843	0.13659	0.05510	0.19169	2.4%	-15.3%	-3.4%
Midnight Service	0.13339	0.06504	0.19843	0.13659	0.05510	0.19169	2.4%	-15.3%	-3.4%
Multiple Service (Other Charges)									
All Night/Midnight Service									
Rate A									
Incandescent Extended Service Lamps									
- $/lamp/month	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
Mercury Vapor Lamps									
- $/lamp/month	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
Light Emitting Diode (LED) Lamps									
- $/lamp/month	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
High Pressure Sodium Vapor Lamps - $/lamp/month									
50 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
70 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
100 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
150 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
200 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
250 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
310 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
400 Watt	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
Low Pressure Sodium Vapor Lamps									
-$/lamp/month	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
Metal Halide Lamps									
-$/lamp/month	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
Induction Lamps									
-$/lamp/month	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
All Other Lamps									
-$/lamp/month	0.93	0.00	0.93	0.98	0.00	0.98	5.4%		5.4%
Rate B									
Incandescent Extended Service Lamps									
- $/lamp/month	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
Mercury Vapor Lamps									
- $/lamp/month	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
Light Emitting Diode (LED) Lamps									
- $/lamp/month	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
High Pressure Sodium Vapor Lamps - $/lamp/month									
50 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
70 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
100 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
150 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
200 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
250 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
310 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
400 Watt	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
Low Pressure Sodium Vapor Lamps									
-$/lamp/month	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
Metal Halide Lamps									
-$/lamp/month	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
Induction Lamps									
-$/lamp/month	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
All Other Lamps									
-$/lamp/month	2.84	0.00	2.84	2.98	0.00	2.98	4.9%		4.9%
LS-2 (Continued)									
Series Service									
Series Service Power Fabtor - $/kVar	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
All Night/Midnight Service									
Incandescent Extended Service Lamps									
-$/lamp/month	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
Mercury Vapor Lamps									
-$/lamp/month	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
High Pressure Sodium Vapor Lamps - $/lamp/month									
50 Watt	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
70 Watt	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
100 Watt	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
150 Watt	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
200 Watt	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
250 Watt	N/A			N/A					
310 Watt	N/A			N/A					
400 Watt	N/A			N/A					
Low Pressure Sodium Vapor Lamps									
-$/lamp/month	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
Metal Halide Lamps									
-$/lamp/month	N/A			N/A					
All Other Lamps									
-$/lamp/month	13.66	0.00	13.66	14.34	0.00	14.34	5.0%		5.0%
Series Service Voltage Discount, Energy - $/kWh	0.00000	(0.00282)	(0.00282)	0.00000	(0.00436)	(0.00436)		54.6%	54.6%

	October 2024 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
LS-2 Continued - (Optional Service - Relamp)									
Incandescent Extended Service Lamps									
-$/lamp/month	N/A			N/A					
Mercury Vapor Lamps									
-$/lamp/month	N/A			N/A					
High Pressure Sodium Vapor Lamps - $/lamp/month									
50 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
70 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
100 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
150 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
200 Watt	0.72	0.00	0.72	0.75	0.00	0.75	4.2%		4.2%
250 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
310 Watt			0.00						
400 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
Low Pressure Sodium Vapor Lamps									
-$/lamp/month	N/A			N/A					
Metal Halide Lamps									
-$/lamp/month	N/A			N/A					
All Other Lamps									
-$/lamp/month	N/A			N/A					
LS-3									
Energy Charge - $/kWh	0.07209	0.06514	0.13723	0.07869	0.05625	0.13494	9.2%	-13.6%	-1.7%
Customer Charge - $/month									
Multiple Service	16.49	0.00	16.49	12.00	0.00	12.00	-27.2%		-27.2%
Series Service	638.76	0.00	638.76	434.84	0.00	434.84	-31.9%		-31.9%
Optional Relamp Service Charge ($/lamp/month)									
High Pressure Sodium Vapor Lamps									
50 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
70 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
100 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
150 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
200 Watt	0.72	0.00	0.72	0.75	0.00	0.75	4.2%		4.2%
250 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
400 Watt	0.71	0.00	0.71	0.75	0.00	0.75	5.6%		5.6%
Series Service									
Voltage Discount, Energy - $/kWh	0.00000	(0.00282)	(0.00282)	0.00000	(0.00436)	(0.00436)		54.6%	54.6%
OL-1									
Energy Charge - $/kWh									
All Night Service	0.13339	0.06504	0.19843	0.13659	0.05510	0.19169	2.4%	-15.3%	-3.4%
Midnight Service	0.13339	0.06504	0.19843	0.13659	0.05510	0.19169	2.4%	-15.3%	-3.4%
Pole Charge - $/pole/month	2.35	0.00	2.35	2.47	0.00	2.47	5.1%		5.1%
Other Charges - All Night/Midnight Service									
Mercury Vapor Lamps - $/lamp/month									
175 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
400 Watt	11.23	0.00	11.23	11.79	0.00	11.79	5.0%		5.0%
High Pressure Sodium Vapor Lamps - $/lamp/month									
50 Watt	10.35	0.00	10.35	10.87	0.00	10.87	5.0%		5.0%
70 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
100 Watt	10.37	0.00	10.37	10.89	0.00	10.89	5.0%		5.0%
150 Watt	10.84	0.00	10.84	11.38	0.00	11.38	5.0%		5.0%
200 Watt	11.22	0.00	11.22	11.78	0.00	11.78	5.0%		5.0%
250 Watt	11.29	0.00	11.29	11.85	0.00	11.85	5.0%		5.0%
400 Watt	11.22	0.00	11.22	11.78	0.00	11.78	5.0%		5.0%
1000 Watt	14.54	0.00	14.54	15.27	0.00	15.27	5.0%		5.0%
Low Pressure Sodium Vapor Lamps - $/lamp/month									
35 Watt			0.00						
55 Watt	12.62	0.00	12.62	13.25	0.00	13.25	5.0%		5.0%
90 Watt	13.32	0.00	13.32	13.99	0.00	13.99	5.0%		5.0%
135 Watt	13.42	0.00	13.42	14.09	0.00	14.09	5.0%		5.0%
180 Watt	13.44	0.00	13.44	14.11	0.00	14.11	5.0%		5.0%
Metal Halide Lamps - $/lamp/month									
70 Watt			0.00						
100 Watt	11.69	0.00	11.69	12.27	0.00	12.27	5.0%		5.0%
175 Watt	11.65	0.00	11.65	12.23	0.00	12.23	5.0%		5.0%
250 Watt	11.43	0.00	11.43	12.00	0.00	12.00	5.0%		5.0%
400 Watt	11.80	0.00	11.80	12.39	0.00	12.39	5.0%		5.0%
1,000 Watt	11.80	0.00	11.80	12.39	0.00	12.39	5.0%		5.0%
1,500 Watt			0.00						
HPSV Recommened (LED) - $/lamp/month									
50 Watt	10.27	0.00	10.27	10.78	0.00	10.78	5.0%		5.0%
70 Watt	10.27	0.00	10.27	10.78	0.00	10.78	5.0%		5.0%
100 Watt	10.35	0.00	10.35	10.87	0.00	10.87	5.0%		5.0%
150 Watt	10.94	0.00	10.94	11.49	0.00	11.49	5.0%		5.0%
200 Watt	11.34	0.00	11.34	11.91	0.00	11.91	5.0%		5.0%
250 Watt	11.65	0.00	11.65	12.23	0.00	12.23	5.0%		5.0%
400 Watt	12.80	0.00	12.80	13.44	0.00	13.44	5.0%		5.0%
1000 Watt	15.44	0.00	15.44	16.21	0.00	16.21	5.0%		5.0%
Distribution Pole Mounted Discount									
$/lamp/month	(4.12)	0.00	(4.12)	(4.97)	0.00	(4.97)	20.6%		20.6%

		October 2024 Rates			Proposed 2025 GRC Rates					
		Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TC-1										
Energy Charge - $/kWh		0.13811	0.09514	0.23325	0.13954	0.10349	0.24303	1.0%	8.8%	4.2%
Customer Charge - $/day		0.995	0.000	0.995	0.851	0.000	0.851	-14.5%		-14.5%
Three-Phase Service - $/day		0.031	0.000	0.031	0.027	0.000	0.027	-12.9%		-12.9%
WTR										
Energy Charge - $/Device/Month										
25	0 - 25 kWh/month	3.46	2.38	5.84	3.50	2.59	6.09	1.2%	8.8%	4.3%
50	26 - 50 kWh/month	6.92	4.76	11.68	6.97	5.17	12.14	0.7%	8.6%	3.9%
100	51 - 100 kWh/month	13.81	9.51	23.32	13.95	10.35	24.30	1.0%	8.8%	4.2%
150	101 - 150 kWh/month	20.71	14.27	34.98	20.92	15.52	36.44	1.0%	8.8%	4.2%
200	151 - 200 kWh/month	27.62	19.03	46.65	27.91	20.70	48.61	1.0%	8.8%	4.2%
250	201 - 250 kWh/month	34.54	23.79	58.33	34.90	25.87	60.77	1.0%	8.7%	4.2%
300	251 - 300 kWh/month	41.44	28.54	69.98	41.86	31.05	72.91	1.0%	8.8%	4.2%
350	301 - 350 kWh/month	48.34	33.30	81.64	48.84	36.22	85.06	1.0%	8.8%	4.2%
400	351 - 400 kWh/month	55.25	38.06	93.31	55.82	41.40	97.22	1.0%	8.8%	4.2%
450	401 - 450 kWh/month	62.14	42.81	104.95	62.79	46.57	109.36	1.0%	8.8%	4.2%
500	451 - 500 kWh/month	69.07	47.57	116.64	69.79	51.75	121.54	1.0%	8.8%	4.2%
900	501 - 900 kWh/month	124.31	85.63	209.94	125.59	93.14	218.73	1.0%	8.8%	4.2%
1350	901 - 1350 kWh/month	186.45	128.44	314.89	188.38	139.71	328.09	1.0%	8.8%	4.2%
1800	1351 - 1800 kWh/month	248.60	171.25	419.85	251.17	186.28	437.45	1.0%	8.8%	4.2%
2250	1801 - 2250 kWh/month	310.76	214.07	524.83	313.98	232.85	546.83	1.0%	8.8%	4.2%
2700	2251 - 2700 kWh/month	372.90	256.88	629.78	376.76	279.42	656.18	1.0%	8.8%	4.2%
Customer Charge - $/Month		14.77	0.00	14.77	21.61	0.00	21.61	46.3%		46.3%
Three-Phase Service - $/day		0.031	0.000	0.031	0.027	0.000	0.027	-12.9%		-12.9%
Inspection Charge - $/Device/Month		15.23	0.00	15.23	15.23	0.00	15.23	0.0%		0.0%
Initialization of Service Charge - One-time charge		7.31	0.00	7.31	7.31	0.00	7.31	0.0%		0.0%
AMI Devices										
Energy Charge - $/Device/Month										
29	29 kWh/month	4.00	2.76	6.76	4.04	3.00	7.04	1.0%	8.7%	4.1%
Customer Charge - $/month		5.43	0.00	5.43	5.06	0.00	5.06	-6.8%		-6.8%
Inspection Charge - $/Device/Month		15.23	0.00	15.23	15.23	0.00	15.23	0.0%		0.0%
Initialization of Service Charge - One-time charge		10.42	0.00	10.42	10.42	0.00	10.42	0.0%		0.0%
Wi-Fi-1										
Energy Charge - $/Device/Month		3.59	2.43	6.02	3.64	2.65	6.29	1.4%	9.1%	4.5%
Customer Charge - $/Month		5.43	0.00	5.43	5.06	0.00	5.06	-6.8%		-6.8%
Inventory/Maintenance Charge - $/Devoce/Month		2.88	0.00	2.88	2.88	0.00	2.88	0.0%		0.0%
Initialization of Service Charge - One time charge/service account		10.42	0.00	10.42	10.42	0.00	10.42	0.0%		0.0%

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

<u>SMALL COMMERCIAL RATE DESIGN</u>
<u>SETTLEMENT AGREEMENT</u>

Dated: **August 7, 2025**

SMALL COMMERCIAL RATE DESIGN SETTLEMENT AGREEMENT

Table of Contents

Section **Page**

SMALL COMMERCIAL RATE DESIGN SETTLEMENT AGREEMENT

Table of Contents (Continued)

Table of Contents (Continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

SMALL COMMERCIAL RATE DESIGN SETTLEMENT AGREEMENT

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), the undersigned Settling Parties in Application (A.) 24-03-019, Application of Southern California Edison Company to Establish Marginal Costs, Allocate Revenues, and Design Rates, enter into this Small Commercial Rate Design Settlement Agreement (Agreement or Settlement Agreement).

1. Parties

The Parties to this Settlement Agreement are Southern California Edison Company (SCE), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Small Business Utility Advocates (SBUA), and California Farm Bureau Federation (CFBF) (collectively, "Small Commercial Settling Parties").

A. SCE is an investor-owned public utility and is subject to the jurisdiction of the CPUC with respect to providing electric service to its CPUC-jurisdictional retail customers.
B. Cal Advocates represents the interests of public utility customers. Its goal is to obtain the lowest possible rate for service consistent with safe, reliable service, and the State's environmental goals. Pursuant to California Public Utilities Code Section 309.5(a), Cal Advocates is directed to primarily consider the interests of residential and small commercial customers in revenue allocation and rate design matters.

C. SBUA represents the interests of small commercial customers of bundled electricity as defined in California Public Utilities Code Section 1802.

D. CFBF is California's largest farm organization, working to protect family farms and ranches on behalf of its nearly 27,000 members statewide and as part of a nationwide network of more than 5.8 million members.

2. **Definitions**

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "Base Rate" means the rate option (*e.g.*, Option E) in a rate group (*e.g.*, TOU-GS-1) against which all other options within the rate group are designed to be revenue neutral.

B. "Basic Charge" means the monthly customer charge applied to customers in the Domestic Rate Group.

C. "CARE" means California Alternate Rates for Energy, which is a program that provides customers meeting a certain household income criteria a discount from SCE's otherwise applicable residential rates.

D. "Commission" or "CPUC" means the California Public Utilities Commission.

E. "Customer Charge" means the fixed dollar-per-month charge applied to customers in the Small Commercial Rate Group that are designed to recover the fixed customer costs of connection to SCE's system.

F. "Demand Charges" mean those charges that are comprised of Facilities-Related Demand (FRD) Charges, which are based on the customer's maximum kilowatt (kW) demand during a billing period, and Time-Related Demand (TRD) Charges, which are based on the customer's maximum kW demand during specified TOU periods. Demand Charges recover a portion of SCE's delivery and generation costs, where such charges apply to a specific rate schedule.

G. "Energy Charges" mean the dollar-per-kilowatt-hour (kWh) charges that recover (1) the portion of SCE's generation services revenues not recovered in TRD Charges; (2) the portion of SCE's delivery services revenues not recovered via Customer or Demand Charges; and, (3) other delivery services revenues for public purpose programs (including Energy

Efficiency and CARE), New System Generation Service (NSGS), Nuclear Decommissioning, CARE balancing account, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and CPUC reimbursement fees. Energy Charges are designed to provide a price signal consistent with marginal cost differentials in TOU energy rates, where TOU energy rates apply to a specific schedule.

H. "Energy Rates" means the volumetric rates paid by residential customers who are served on SCE's residential rate schedules.

I. "EPMC" means equal percent of marginal cost. Because marginal cost revenues do not equal the utility's revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group's percentage share of marginal cost revenue responsibility by function (*i.e.*, separately for generation costs, and for combined distribution and customer costs). The marginal cost revenues of all rate groups are scaled using the same EPMC multipliers – one multiplier for generation and one for distribution – so that total system generation and distribution revenues equal the Commission-approved revenue requirements.

J. "Facilities-Related Demand Charges" or "FRD Charges" mean charges applied to customers' monthly maximum demands, not differentiated by TOU or by season, that are designed to recover certain transmission and distribution costs.

K. "FERA" means the Family Electric Rate Assistance program, which provides customers meeting a certain household income and size criteria a discount from SCE's otherwise applicable residential rates.

L. "FERC" means the Federal Energy Regulatory Commission.

M. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change ("SAPC") for the particular function, *e.g.*, generation, or distribution and customer costs. In addition, this would include adjustments of FERC-jurisdictional transmission revenues as authorized by formula rates or otherwise.

N. "Solar Legacy Customer" means an eligible residential customer who meets one of the two following criteria: (1) completed an interconnection application for a NEM successor tariff (also referred to as NEM-ST or NEM 2.0) prior to the implementation of default TOU rates for residential customers pursuant to Decision (D.) 16-01-044; or (2) submitted an initial interconnection application for an on-site solar generating facility not served on a NEM-ST tariff on or before January 31, 2017 and who opted into a TOU rate as of July 31, 2017. The duration of the legacy period is five years from the customer's permission to operate (PTO) date, except for NEM 2.0 customers who are eligible for legacy rates for five years from the date that they first took service on the TOU rate.

O. "MCRA Settlement Agreement" means the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on June 30, 2025.

P. "NCO" means New Customer Only, and is a method use to derive marginal customer access costs, taking into account the capital cost of adding new customers only and other operations and maintenance (O&M) costs.

Q. "OAT" means "Otherwise Applicable Tariff."

R. "PLRF," means "Peak Load Risk Factor," and represents the methodology used to assess capacity constraints on the distribution system and to assign peak-capacity-related design demand marginal costs to TOU periods.

S. "RECC," or "Real Economic Carrying Charge," means the percentage of a utility investment which corresponds to the first year of a stream of numbers where the net present value of revenue requirements of a utility investment is adjusted to rise at the rate of inflation over the life of the investment. It also represents the value of deferring a utility investment by a year.

T. "Small Commercial Rate Group" means the TOU-GS-1 rate group, which is comprised of customers with demands up to 20 kW taking service on the various schedules listed in Paragraph 4.B.3.

U. "Time-Related Demand Charges" or "TRD Charges" are either generation-related, marginal cost-based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities, or distribution-related, marginal cost-based, peak-related charges assigned to TOU periods based on PLRFs.

V. "TOU" means time-of-use. These are the time periods established for the provision of electric service in which Demand Charges and/or Energy Charges may vary across time periods in relation to the cost of service, as adopted in Decision (D.)18-07-006.[1]

---

[1] *See* SCE's Rate Design Window Application 16-09-003 (2016 RDW).

3. Recitals

A. In Phase 2 of SCE's 2025 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each group.

B. On March 29, 2024, SCE filed its 2025 GRC Phase 2 application (A.24-03-019) and served its initial prepared testimony regarding marginal costs, revenue allocation and rate design.

C. On August 26, 2024, SCE filed its Amended Application and served amended versions of its initial prepared testimony and supplemental testimony regarding changes to 2025 GRC Phase 2 residential rate designs to include a fixed charge structure as adopted in D.24-05-028.

D. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a June 3, 2024 prehearing conference.

E. Cal Advocates served its initial testimony on November 22, 2024 relating, among other matters, to SCE's small commercial rate design proposals.

F. Cal Advocates served amended testimony on December 27, 2024.

G. On January 8, 2025, TURN, SBUA, SEIA, submitted prepared testimony regarding small commercial rate design matters.[2]

H. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on January 3, 2025. Continuing settlement discussions occurred among the parties after that date.

I. On July 9, 2025, SCE provided notice to all parties pursuant to CPUC Rule of Practice and Procedure 12.1(b) of a settlement conference to review this Agreement.

J. The Small Commercial Settling Parties have evaluated various small commercial rate design proposals in this proceeding, desire to resolve all issues related to the design of those rates, and have each reached agreement as indicated in Paragraph 4 of this Agreement.

K. Appendix A to this Agreement provides a comparison of the Small Commercial Settling Parties' positions related to small commercial rate design issues that have been resolved by this Agreement.

[2] CFBF did not serve testimony on small commercial rate design issues.

4. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Small Commercial Settling Parties agree to the respective terms of this Agreement related to the design of small commercial rates. The Small Commercial Settling Parties agree to the terms set forth in Paragraph 4.A., below, and Paragraphs 5-16. Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit or that its position has greater or lesser merit than the position taken by any other Settling Party to the applicable terms of the Agreement. This Agreement is subject to the express limitation on precedent described in Paragraph 11. Unless provided otherwise, such as in Paragraph 11, this Agreement and its terms are intended to remain in effect from the date rate changes are implemented as a result of a CPUC decision in this proceeding until a decision is implemented in Phase 2 of SCE's 2025 GRC.

A. SMALL COMMERCIAL RATE GROUP RATE DESIGN

1) Illustrative Rates

The Small Commercial Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the Small Commercial Class's share of SCE's October 1, 2024, consolidated revenue requirement of $17,466 million described in more detail in Paragraph 4.B.1 of the MCRA Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the MCRA Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

2) Common Rate Design Principles

a) Rate Structure Elements

Consistent with SCE's Application, rate structures for the Small Commercial Rate Group will generally consist of Customer Charges, TOU Energy Charges, TRD Charges, and FRD Charges. Demand Response (*e.g.*, CPP, SDP) and the currently available real-time pricing (RTP) rate schedules will also be available.

i. **Customer Charges**

Upon initial implementation of this Agreement, the Customer Charges in the Small Commercial Rate Group (except for the Energy Storage TOU-GS-1-ES option), shall be set at $17.09 per month, and collected on a $0.562 cents-per-day basis. Thereafter, the Customer Charges shall remain fixed during the attrition years of the 2025 GRC.

ii. **Energy Charges**

Proposed Energy Charges based on the consolidated revenue requirement used in the MCRA Settlement Agreement are set forth in Appendix B of this Agreement.[3] When this Agreement is first implemented, these estimated Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MCRA Settlement Agreement.[4] Thereafter, these estimated Energy Charges shall be adjusted consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement when SCE's authorized revenues change.

(a) **Generation Revenues**

With the exception of the Option D and the legacy B rate structures, all generation energy and capacity revenues are recovered entirely via Energy Charges for the Small Commercial Rate Group. For Option D, all generation energy revenues and a portion of generation capacity revenues are recovered via Energy Charges. The balance of generation capacity revenues is recovered via Demand Charges.

(b) **Distribution Revenues**

With the exception of the Option D, LG,[5] legacy Option B, and legacy Option C rate structures, all distribution peak-capacity and grid-related costs are recovered entirely via Energy Charges, with the peak-capacity portion time-differentiated using a settled version of PLRFs. For Option D, TOU Energy Charges recover approximately 15 percent of the distribution revenues. The balance of peak-capacity revenues and all grid-related revenues are recovered via Demand Charges.

---

[3] The consolidated revenue requirement is $17,466 million and is described in more detail in Paragraph 4.B.1. of the MCRA Settlement Agreement.

[4] *See* Paragraph 4.B.6 of the MCRA Settlement Agreement.

[5] Option LG stands for "local government" and is a rate option only available to RES-BCT generating accounts.

(c) **Other Revenues**

Energy Charges that are designed to recover revenues associated with transmission, public purpose programs, new system generation service, nuclear decommissioning, CARE balancing account, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and the CPUC reimbursement fee shall be established on the basis of the specified functional authorized revenue requirements and the terms specified in the MCRA Settlement Agreement.

iii. **Demand Charges**

For the Small Commercial Rate Class, Options D, LG, and the legacy Options B and C contain Demand Charges. For Option D and legacy Option B, Demand charges consist of both TRD Charges and FRD Charges. TRD Charges are applied in the summer on-peak period and winter mid-peak periods for Option D and applied in the summer on-peak and mid-peak periods for legacy Option B. FRD Charges are not differentiated by season or TOU periods.

(a) **TRD Charges**

Option D shall have both a summer on-peak distribution and generation TRD Charge, and a winter mid-peak distribution and generation TRD Charge, as shown in Table 4-1 below.[6] Legacy B shall have both a summer on- and mid-peak TRD charge.

Table 4-1
Illustrative Time-Related Demand Charges

TOU-GS-1, Option D	Distribution	Generation	Total
Summer On-Peak ($/kW-Month)	$6.61	$10.37	$16.98
Winter Mid-Peak ($/kW-Month)	$1.29	$3.88	$5.17

When this Agreement is first implemented, these illustrative TRD Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MCRA Settlement Agreement.[7] Thereafter, these

6 TRD Charges apply on non-holiday weekdays only, not on weekends or holidays.
7 *See* Paragraph 4.B.6 of the MCRA Settlement Agreement.

illustrative TRD Charges shall be adjusted consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement when SCE's authorized revenues change.

(b) FRD Charges

With the exception of Option LG and legacy Option C, an FRD Charge is established to recover 100 percent of the grid-related portion of distribution design demand marginal costs, the portion of peak-related distribution design demand marginal costs not recovered via Energy or TRD Charges and transmission revenues, as shown in Table 4-2 below.

Table 4-2
Illustrative FRD Charges

TOU-GS-1, Option D	Total
FRD Charge ($/kW-Month)	14.74

When this Agreement is first implemented, the illustrative FRD Charges shall be adjusted, as necessary, consistent with SCE's then-current authorized revenues and the MCRA Settlement Agreement. The distribution component of the illustrative FRD Charge shall be adjusted, as necessary, by the appropriate Functional SAPC distribution scalar when SCE's authorized distribution revenues change. Similarly, the transmission component of the illustrative FRD Charge shall be adjusted, as necessary, when FERC-authorized transmission revenues change.

iv. Voltage Discounts

Customers served at higher voltage delivery levels than the design voltage level for their rate group will receive a voltage discount reflecting their lower cost of service. SCE will establish the discount levels based on the difference in marginal costs of service between the design, or predominant, voltage level for a given rate group and the higher voltage service options. Voltage discounts shall apply to rate schedules in the Small Commercial Rate Group as indicated in Appendix B and will continue to be assessed as a separate and distinct rate from the Customer Charge.

v. Three-Phase Surcharge

SCE shall assess a surcharge when three-phase service is taken. Standard service is provided as single-phase. Customers can opt for taking service at three-phase, which is differentiated on a cost basis by the distribution facilities required by the higher service level. The service-phase surcharges are based on customer cost differentials and the use of SCE's RECC method for determining the associated marginal customer costs. Service-phase surcharges shall apply to rate schedules in the Small Commercial Rate Group, as indicated in Appendix B.

vi. Demand Response Credits (CPP, SDP)

The level of credits that are provided for non-firm service, including price-based and reliability-based demand response programs, shall reflect the incentive budget at the current level as shown in Appendix B to this Agreement.

b) TOU and Seasonal Periods

There are no changes to the existing TOU and seasonal definitions.

3) Schedules in the Small Commercial Rate Group

Illustrative proposed rates for the Small Commercial Rate Group are listed in Appendix B of this Agreement.

a) Schedule TOU-GS-1, Option E (Base Rate)

Schedule TOU-GS-1, Option E shall serve as the Base Rate for Schedule TOU-GS-1. As described above, Option E contains a Customer Charge and TOU Energy Charges, but no Demand Charges. Key rate design features specific to this rate option include the following:

- Moderated seasonal differentials: set at $0.04000/kWh for generation and $0.03149/kWh for distribution;
- Moderated TOU Energy Charge differentials in the summer and winter periods;
- $17.09 per month ($0.562 per day) Customer Charge that will remain fixed during the attrition years; and
- $3.59 per month ($0.118 per day) three-phase charge.

b) Schedule TOU-GS-1, Option D (Optional Rate)

Schedule TOU-GS-1, Option D shall serve as optional rate for Small Commercial customers. As described above, Option D contains a customer charge, TOU Energy Charges, and Demand Charges, as reflected in Appendix B and described below. There are no additional eligibility or participation limitations associated with this rate schedule.

- Customer charge, established at $17.09 per month ($0.562 per day), that will be fixed during the attrition years;
- FRD charge, inclusive of transmission and distribution charges, is set at $17.67/kW-month (Distribution set at $14.74/kW-month and Transmission set at $2.93/kW-month based on October 2024 rates) and will scale with the SAPC adjustment in the attrition years for GRC.
- TRD charge of $16.98/kW-month in the summer and $5.17/kW-month in the winter.

c) <u>Schedule TOU-GS-1, Option ES (Optional Storage Rate)</u>

Schedule TOU-GS-1, Option ES is an optional rate available only to customers who install behind the meter (BTM) storage. Participation on this rate will be capped at 15,000 customers. Participants will be required to have a minimum energy storage capacity equal to the greater of either 4.8 kW per hour or at least 0.05 percent of the customer's annual usage (in kWh) over the previous months.[8] Customers who take service on Option ES are exempt from Standby service until the implementation of SCE's next GRC Phase 2, at which time the Standby exemption may or may not continue to apply depending on the outcome of a decision in that subsequent proceeding.

Option ES utilizes the same rate design structure as Option E (*i.e.*, Customer Charge, TOU Energy Charges, no Demand Charges), but includes the following differences:

- TOU Energy Charges are not moderated compared to Option E and contain no "flattening"; and,
- Customer Charge shall be set at $32.01/month during implementation and subsequently scaled in the attrition years using an SAPC scalar excluding wildfire-related costs[9];

d) <u>Schedule TOU-GS-1, Option CPP</u>

The Settling Parties agree that Option CPP will no longer be the default rate option for eligible TOU-GS-1 customers. Additionally, customers on CPP who do not perform for

[8] For customers with less than 12 months of annual usage data, the energy storage system must have a minimum energy storage capacity of at least 4.8 kW per hour.

[9] See MCRA Settlement Agreement, p.23.

two consecutive years will be removed from the program. Non-performance is defined as those customers generating less than $20 in net annual savings. SCE will also remove “structural benefitters” from the program, with “structural benefitters” being defined as those customers who show higher-than-average usage on event days compared to average usage on non-event days for two consecutive years. Customers removed from CPP will default to Option E. Finally, SCE plans to send communications to inform customers about being removed from the program.

The CPP event periods will continue to coincide with the updated peak periods (*i.e.*, weekdays from 4-9 p.m.). The dispatch hours will be modified to allow for 60 hours of events per year, resulting in 20 events per year. CPP credits with be provided as a $/kWh credit on Summer Season weekdays 4:00 p.m. – 9:00 p.m., when a CPP Event is not occurring. The CPP Event Charge shall be set at $0.80/kWh. Bill protection will be offered to customers for up to one year, accrued monthly, and paid at the end of the bill protection period. This means that a customer on Option CPP is billed an amount no greater than what the customer would have been billed under the customer’s OAT. Customers are permitted to opt-out of participating on Option CPP.

e) <u>Schedule TOU-GS-1, Option LG (RES-BCT Generating Accounts Only)</u>

SCE shall offer Option LG exclusively for TOU-GS-1 customers taking service on Schedule RES-BCT (Generating Account only),[10] which shall include a Customer Charge, established at $17.09 per month ($0.562 per day) that will remain fixed during the attrition years, and an FRD Charge. Customers taking service on Option LG are required to take service on Schedule S as a rider.[11]

- FRD charge inclusive of transmission and distribution charges is set at $11.42/kW-month (Distribution set at $8.49/kW-month and

---

[10] Schedule RES-BCT is an optional rate for local governments and campuses who own and operate an Eligible Renewable Generating Facility, as defined in the tariff, with a total effective generation capacity of not more than 5 MW. Schedule RES-BCT allows Local Governments or Campuses to generate energy from an Eligible Renewable Generating Facility for its own use (Generating Account) and to export energy not consumed at the time of generation by the Generating Account to SCE’s grid. All generation exported to SCE’s grid is converted into dollar credits and applied to the Benefiting Accounts designated by the Local Government or Campus. Only the Generating Account is required to take Standby service; therefore, Option LG is only available to the Generating Account (not to benefitting accounts).

[11] Schedule S consists of a $8.49-per-kW capacity reservation charge, applied to a monthly standby demand. Back-up TRD Charges are not applicable.

Transmission set at $2.93/kW-month based on October 2024 rates) and will scale with the SAPC adjustment in the attrition years.

f) Legacy TOU Rate Schedules

Schedules TOU-GS-1-A, TOU-GS-1-B, and TOU-GS-1-C will remain closed to new customers. Eligible customers will remain on these rate options only until their legacy periods have ended[12]. No structural changes are agreed to for these rates. The customer charge for these schedules shall be set at $17.09 per month ($0.562 per day) and will remain fixed during the attrition years.

g) RTP

Small Commercial customers will remain eligible for the RTP rate option. No structural changes to the RTP program are proposed in this Agreement. Rates for TOU-GS-1-RTP will be established as reflected in Appendix B to this Agreement.

h) GS-APS-E

Schedule GS-APS-E is an interruptible "summer discount plan" for Small Commercial customers. No structural changes to GS-APS-E are proposed in this Agreement. Illustrative rates reflecting the incentive budget at the current levels are reflected in Appendix B to this Agreement.

i) Schedule TOU-GS-2 Option D (Default Rate)

Existing eligibility requirements are maintained (*i.e.,* C&I customers with demands above 20 kW up to 199 kW with no other eligibility restrictions). Option D incorporates the following rate design:

- TOU periods as adopted in D.18-07-006, with a 4:00PM to 9:00PM on-peak period;
- The Customer Charge shall be set at $232.74/month, thereafter, the Customer Charges shall remain fixed during the attrition years of the 2025 GRC;

[12] Legacy TOU-GS-1 and TOU-GS-2 rate schedules will migrate off Legacy rates from October - December of 2027.

- FRD charge inclusive of transmission and distribution charges is set at \$25.47/kW-month (Distribution set at \$21.67/kW-month and Transmission set at \$3.80/kW-month based on October 2024 rates);
- For distribution, a summer on-peak TRD Charge that recovers summer on-, mid- and five percent (5%) of off-peak capacity costs; a winter mid-peak TRD charge that recovers all winter peak capacity costs;
- TOU Energy Charges to recover ninety-five percent (95%) of summer off-peak capacity cost revenues across all TOU periods as an energy charge;
- The Summer-mid and Summer-off energy charges are set based on the average energy rate that recovers 95% of summer-off peak capacity cost revenues across all TOU-periods;
- A 10% adder is then applied to this average rate to set the Summer-on and Winter-mid energy charges with the Winter-Super-off and the Summer-off then residually set to recover the remainder of the Summer off-peak capacity cost revenues;
- The FRD Charge is set to recover Grid Marginal cost revenues and an incremental adder to recover the shortfall in customer charge revenues that results from setting the customer charge lower than its scaled marginal cost;
- The generation, summer on-peak capacity cost revenues are recovered via the Summer on-peak TRD charge, and all winter capacity cost revenues are recovered via winter mid-peak TRD Charge. 79% of the Summer mid- and off-peak scaled capacity cost revenues are included in summer on-peak energy charge with the residual 21% included in the summer mid-peak energy charges;

- Generation energy cost revenues are recovered via volumetric TOU Energy Charges in the respective TOU periods.

j) <u>Schedule TOU-GS-2 Option E</u>

Option E incorporates the following rate design elements:

- TOU periods as adopted in D.18-07-006, with a 4:00PM to 9:00PM on-peak period:
- The Customer Charge shall be set at $232.74/month, thereafter, the Customer Charges shall remain fixed during the attrition years of the 2025 GRC;
- An FRD charge inclusive of transmission and distribution charges is set at $12.75kW-month (Distribution set at $8.95/kW-month and Transmission set at $3.80/kW-month based on October 2024 rates);
- For distribution, recovery of sixty percent (60%) of revenues (excluding Customer Charge revenues) via TOU Energy Charges using PLRFs agreed to in the MCRA Settlement Agreement, thirty percent (30%) via an FRD Charge, and ten percent (10%) via flat cent-per-kWh Energy Charges.
- For generation, the TRD charge is set at twenty-five percent (25%) of the equivalent Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges for each season.

k) <u>Schedule TOU-GS-2, Option CPP</u>

The Settling Parties agree that Option CPP will no longer be the default rate option for eligible TOU-GS-2 customers. Additionally, customers on CPP who do not perform for two consecutive years will be removed from the program. Non-performance is defined as those customers generating less than $20 in net annual savings. SCE will also remove "structural benefitters" from the program, with "structural benefitters" being defined as those customers who show higher-than-average usage on event days compared to average usage on non-event days for two consecutive years. Customers removed from CPP will default to Option D. Finally, SCE plans to send communications to inform customers about being removed from the program.

The CPP event periods will continue to coincide with the updated peak periods (*i.e.*, weekdays from 4-9 p.m.). The dispatch hours will be modified to allow for 60 hours of events per year, resulting in 20 events per year. CPP credits with be provided as a $/kWh credit on Summer Season weekdays 4:00 p.m. – 9:00 p.m., when a CPP Event is not occurring. The CPP Event Charge shall be set at $0.80/kWh. Bill protection will be offered to customers for up to one year, accrued monthly, and paid at the end of the bill protection period. This means that a customer on Option CPP is billed an amount no greater than what the customer would have been billed under the customer's OAT. Customers are permitted to opt-out of participating on Option CPP.

l) Updates to SCE Communication Materials

Parties agree to update the TOU-GS-2 Rate Fact Sheet to provide consistent explanations to the TOU-GS-1 Rate Fact Sheet. Additionally, Parties agree to update SCE's Business Connection webpage to ensure consistency with the updated TOU-GS-2 Rate Fact Sheet. Parties also agree to a yearly bill insert education write-up to TOU-GS-1 and TOU-GS-2 customers reflective of the Rate Fact Sheets.

m) Standby Service for Customers in the Small Commercial Rate Group

Customers who provide all or a portion of their energy needs from a non-NEM generator are required to take standby service. The Standby Capacity Reservation Charge (CRC)[13] shall be applied to the customer's standby demand level as specified in Schedule S Standby.[14]

4) Budget Billing Plan (BBP)

SCE's proposal to expand its Budget Billing Program (BBP) to allow single-phase TOU-GS-2 customers to participate shall be approved. The extension will be limited to approximately 100 customers.

---

[13] Standby Capacity Reservation Charge (CRC) is a monthly charge based on the established Standby demand value. This charge is calculated by multiplying the Standby demand value by the applicable CRC price. The CRC is billed every month regardless of the maximum demand registered on the meter.

[14] Customers on Option ES are exempt from Schedule S, Standby.

5) Implementing Future Revenue Changes in Rates

As described in the MCRA Settlement Agreement, when SCE's authorized revenues change in the future, SCE will first adjust rate levels for the base rate schedule (without CPP), *i.e.*, Schedule TOU-GS-1-E, using a Functional SAPC adjustment, with the customer charge remaining fixed as described in Paragraph 4.B.2 above[15]. SCE will then rebalance optional rate levels to ensure revenue neutrality between the base rate schedule and the optional rate schedules. For example, generation revenue changes resulting from SCE's Energy Resource Recovery Account (ERRA) proceedings shall be allocated on a Functional SAPC basis, *i.e.*, the revised SCE generation revenue requirement would be allocated by applying a generation-level SAPC scalar based on the difference between present rate revenues and proposed rate revenues for the default rate schedules. The optional rate schedules will then be adjusted to ensure revenue neutrality on a functional basis.

6) Food Bank Rate

To comply with Assembly Bill 2218[16] and California Public Utilities Code Section 739.3, SCE will continue to provide eligible food banks, as defined in California Public Utilities Code Section 739.3(c)(1), a 20 percent discount on their OAT bill.

5. Implementation of Settlement Agreement

It is the intent of the Small Commercial Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1 of 2026.

5. Incorporation of Complete Agreement

The Small Commercial Settling Parties intend the terms described at the outset of Paragraph 4.A to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Small Commercial Settling Parties acknowledge that changes, concessions, or compromises by any Settling Party or Settling Parties in one section of the

---

[15] See the Customer Charge adjustment described for Option ES in section 3.c. of this Agreement.
[16] Assembly Bill (AB) 2218, Bradford (2014), codified in the Public Utilities Code Section 739.3.

applicable terms of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Small Commercial Settling Parties agree to oppose any modification in each of the applicable terms of this Agreement not agreed to by all Settling Parties who agreed on those terms. If the Commission does not approve this Agreement without modification, the Settling Parties to whom that change is relevant in the Agreement shall promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties as set forth in Section 9 below, and shall promptly seek Commission approval of the resolution so achieved.

5. <u>Record Evidence</u>

The Small Commercial Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

5. <u>Signature Date</u>

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

5. <u>Regulatory Approval</u>

The Small Commercial Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's 2025 GRC. The Small Commercial Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Small Commercial Settling Parties shall request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with the law, and in the public interest. Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Small Commercial Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties for the respective settlement within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Small Commercial Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

10. Compromise of Disputed Claims

This Settlement Agreement represents a compromise of disputed claims between the Small Commercial Settling Parties for each of the terms to which they have agreed. The Small Commercial Settling Parties have each independently reached an agreement on the issues related to the design of those rates after taking into account the possibility that each Party may or may not prevail on any given issue. The Small Commercial Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

11. Non-Precedential

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before this Commission.

The Small Commercial Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2025 GRC or in another proceeding if invited by the Commission. Barring Commission-ordered modifications to this Settlement Agreement, the Settling Parties will support the continued applicability of Section 4 until the date on which SCE's tariffs implementing its 2025 GRC Phase 2 becomes effective.

12. Previous Communications

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to small commercial rate design issues. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

13. Non-Waiver

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

14. Effect of Subject Headings

Subject headings in this Settlement Agreement are inserted for convenience only and shall not be construed as interpretations of the text.

15. Governing Law

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. Number of Originals

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: August 5, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Michael Backstrom

By: Michael Backstrom
Title: Senior Vice President, Regulatory Affairs

Dated: August 5, 2025

PUBLIC ADVOCATES OFFICE

/s/ Michael Campbell

By: Michael Campbell
Title: Deputy Director

Dated: August 5, 2025

SMALL BUSINESS UTILITY ADVOCATES

/s/ Britt Marra

By: Britt Marra
Title: Executive Director

Dated: August 5, 2025

CALIFORNIA FARM BUREAU FEDERATION

/s/ Kevin Johnston

By: Kevin Johnston
Title: Director and Counsel

Appendix A

Comparison of Party Positions on Small Commercial Rate Design Matters and Settlement

Comparison of Positions
Small Commercial Rate Design Issues

	SCE	Cal Advocates	SBUA	2025 GRC Settled Position
TOU-GS-1, Option E Rate Design (Base Rate)	• Energy charges based on marginal costs and revenue allocations from Exhibits SCE-02 and SCE-03 • Maintain "all volumetric" energy rate structure (*i.e.*, no demand charges) with a 2.70 Jan 25 Update (2.46 ERRATA) on/off peak rate differential ratio in summer and a 1.63 Jan 25 Update (1.67 ERRATA) mid/SOP • ratio in winter • $23.89/mo. Jan 25 Update ($18.87/mo. ERRATA) . customer charge for single phase and $34.21/mo. Jan 25 Update ($27.02/mo. ERRATA) for three-phase to recover customer-related distribution marginal costs (use RECC)	• Should maintain current fixed charge levels. Proposes $4.89/mo. customer charge for single phase and a $8.46/mo. charge for three phase using own marginal costs (use NCO), rejects SCE's proposal to apply EPMC scalar for TOU-GS-1 customer charge and recommends their EPMC MCACs • Should maintain SCE's current method for determining variable distribution rates and reject SCE's proposal to update seasonal energy charges	• TOU-GS-1 customer service costs are overallocated. Rejects the increase in customer charge for TOU-GS-1 • Rejects Cal Advocates MCAC model, which removes uncollectibles and assumes a uniform growth rate for non-res customers. • TOU-GS-1 cut off is too low and should be 50kW	• Customer charge to be set at $17.09 during implementation and shall remain fixed during the attrition years • Energy charges to have moderated seasonal differentials
TOU-GS-1, Option D (Optional Rate)	• Rate design using marginal costs and revenue allocations from Exhibits SCE-02 and SCE-03. • For generation energy, recover via TOU energy charges • For generation capacity, summer on-peak and winter mid-peak costs are recovered via TRD charges; summer mid-peak and off-peak costs are recovered via TOU energy charges • Time-differentiated distribution by recovering 50% of peak-related distribution design demand costs in smoothed TOU energy charges, and the balance for summer on-peak via a TRD		•	• Customer charge to be set at $17.09 during implementation and shall remain fixed during the attrition years • Adopt SCE's proposal on other rate design elements

	SCE	Cal Advocates	SBUA	2025 GRC Settled Position
	charge and the balance of all other periods via an FRD charge; recover 100% of grid-related distribution design demand costs via an FRD charge • $23.89 Jan 25 Update ($18.87 ERRATA) /mo customer charge for single phase and $34.21 Jan 25 Update ($27.02 ERRATA) for three-phase to recover customer-related distribution marginal costs (use RECC)			
TOU-GS-1 Option LG (Optional rate for RES-BCT Generating Accounts Only)	• Rate design using marginal costs and revenue allocations from Exhibits SCE-02 and SCE-03		•	• Customer charge to be set at $17.09 during implementation and shall remain fixed during the attrition years • Adopt SCE's proposal on other rate design elements
TOU-GS-1, Option ES (Optional Rate available only to customers who install BTM storage)	• Rate design using marginal costs and revenue allocations from Exhibits SCE-02 and SCE-03			• Customer charge to be set at $32.01 during implementation and subsequently scaled in the attrition years using the SAPC scalar excluding wildfire-related cost
TOU Rates w/Legacy TOU periods (Option A, B, and C)	• The existing rates will remain available to legacy customers until Q4 of 2027. Update existing rates using marginal cost and revenue allocation proposals			• Adopt SCE's proposals but use revenue allocation for small commercial customers adopted in the Revenue Allocation Settlement Agreement

	SCE	Cal Advocates	SBUA	2025 GRC Settled Position
CPP Proposal	• SCE proposed to make the following changes to its CPP program: 1) make CPP an opt-in rate schedule, 2) modify the dispatch hours to allow for 60 hours of events per year, and 3) remove non-performing customers from the program	• Supports updating the length/ frequency of CPP events. Rejects disenrolling non-performers. Recommends SCE adopt SDG&Es approach as it relates to opt-in, and allow existing customers to continue on CPP, unless they opt-out, and by changing the default enrollment for new customers to opt-in	• Supports SCE's proposal in its entirety	• Make CPP an opt-in program for new customers • Modify the dispatch hours to 60 hrs of events per year, resulting in 20 events per year • Remove non-performing and structural benefiters from program on annual basis (if non-performing or structural benefiter over a two-year period) • Communications to customers being removed from program
Single and Three-Phase Adjustments	• SCE proposes to make changes to how the default customer charge will now be set based on the typical phase of service for the group: single-phase for TOU-GS-1, and three phase for TOU-GS-2. The surcharge and surcredit are based on the equal-percent-marginal-cost difference between single phase and three phase service customer charges after accounting for any rate design elements generally adopted in setting the default customer charge for the respective rate group	• Should use their MCACs to inform the fixed charge differentials between single and three phase services	• Reject proposal to decrease the three phase service adder	• Adopt SCE's proposal to base customer charge on the typical phase of service for the group: single-phase for TOU-GS-1, and three phase for TOU-GS-2
Budget Billing Plan (BBP)	• Expand eligibility to approximately 100 TOU-GS-2 customers			• Adopt expansion of program to approximately 100 TOU-GS-2 customers

Appendix B

Illustrative Small Commercial Rate Group Rates

Table 1-1
Illustrative Rates: TOU-GS-1-E

	October 2024 TOU-GS-1 Option E					Proposed TOU-GS-1 Option E CALPA				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$14.24			**$14.24**		$17.09			**$17.09**
Summer season										
On-peak $/kWh	0.01404	0.14796	0.44305	0.03615	**$0.64120**	0.01404	0.20171	0.35764	0.03631	**$0.60971**
Mid-peak $/kWh	0.01404	0.14796	0.11795	0.03615	**$0.31610**	0.01404	0.18307	0.11863	0.03631	**$0.35205**
Off-peak $/kWh	0.01404	0.09936	0.08432	0.03615	**$0.23387**	0.01404	0.09533	0.09212	0.03631	**$0.23780**
Winter season										
Mid-peak $/kWh	0.01404	0.14796	0.17901	0.03615	**$0.37716**	0.01404	0.08851	0.17480	0.03631	**$0.31366**
Off-peak $/kWh	0.01404	0.09936	0.09944	0.03615	**$0.24899**	0.01404	0.08254	0.10694	0.03631	**$0.23983**
SOff-peak $/kWh	0.01404	0.07663	0.05220	0.03615	**$0.17902**	0.01404	0.09222	0.04726	0.03631	**$0.18983**
Three Phase Adder		1.40					$3.59			

Table 1-2
Illustrative Rates: TOU-GS-1-D

	October 2024 TOU-GS-1 Option D					Scenario 3 TOU-GS-1 Option D				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$14.24			**$14.24**		$17.09			**$17.09**
Summer season										
On-peak $/kWh	(0.00003)	0.03989	0.11880	0.03615	**$0.19481**	(0.00003)	0.03001	0.13814	0.03631	**$0.20443**
Mid-peak $/kWh	(0.00003)	0.03989	0.10728	0.03615	**$0.18329**	(0.00003)	0.02723	0.10160	0.03631	**$0.16511**
Off-peak $/kWh	(0.00003)	0.01594	0.07031	0.03615	**$0.12237**	(0.00003)	0.01418	0.08899	0.03631	**$0.13946**
On-MW		4.81	16.74		**21.55**		6.61	10.37		**$16.98**
Max-MW	2.93	16.65			**19.58**	2.93	14.74			**$17.67**
Winter season										
Mid-peak $/kWh	(0.00003)	0.03989	0.11182	0.03615	**$0.18783**	(0.00003)	0.01364	0.10279	0.03631	**$0.15272**
Off-peak $/kWh	(0.00003)	0.01594	0.07894	0.03615	**$0.13100**	(0.00003)	0.01272	0.10692	0.03631	**$0.15592**
SOff-peak $/kWh	(0.00003)	0.00514	0.05906	0.03615	**$0.10032**	(0.00003)	0.01422	0.04726	0.03631	**$0.09775**
Mid-MW			5.14		**5.14**		1.29	3.88		**$5.17**
Max-MW	2.93	16.65			**19.58**	2.93	14.74			**$17.67**
Three Phase Adder		$1.40					$3.59			

Table 1-3
Illustrative Rates: TOU-GS-1-ES

	October 2024 TOU-GS-1 Option ES					Scenario 1 Proposed TOU-GS-1 Option ES				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$35.68			**$35.68**		$32.01			**$32.01**
Summer season										
On-peak $/kWh	0.01404	0.26835	0.47878	0.03615	**$0.79732**	0.01404	0.20603	0.35771	0.03631	**$0.61410**
Mid-peak $/kWh	0.01404	0.16152	0.13120	0.03615	**$0.34291**	0.01404	0.18699	0.11866	0.03631	**$0.35600**
Off-peak $/kWh	0.01404	0.10258	0.09072	0.03615	**$0.24349**	0.01404	0.09737	0.09214	0.03631	**$0.23986**
On-MW										
Max-MW										
Winter season										
Mid-peak $/kWh	0.01404	0.05729	0.16944	0.03615	**$0.27692**	0.01404	0.06192	0.17477	0.03631	**$0.28704**
Off-peak $/kWh	0.01404	0.04632	0.09174	0.03615	**$0.18825**	0.01404	0.05774	0.10692	0.03631	**$0.21501**
SOff-peak $/kWh	0.01404	0.05381	0.04851	0.03615	**$0.15251**	0.01404	0.06451	0.04726	0.03631	**$0.16212**
Mid-MW										
Max-MW										
Three Phase Adder		$1.40					$3.59			

Table 1-4
Illustrative Rates: TOU-GS-1-LG

	October 2024 TOU-GS-1 Option LG					Scenario 1 Proposed TOU-GS-1 Option LG				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$14.24			**$14.24**		$17.09			**$17.09**
Summer season										
On-peak $/kWh	(0.00003)	0.14343	0.44305	0.03615	**$0.62260**	(0.00003)	0.12128	0.35772	0.03631	**$0.51527**
Mid-peak $/kWh	(0.00003)	0.14343	0.11795	0.03615	**$0.29750**	(0.00003)	0.11007	0.11866	0.03631	**$0.26500**
Off-peak $/kWh	(0.00003)	0.05733	0.08432	0.03615	**$0.17777**	(0.00003)	0.05732	0.09214	0.03631	**$0.18574**
On-MW										
Max-MW	2.93	7.81			**10.74**	2.93	8.49			**$11.42**
Winter season										
Mid-peak $/kWh	(0.00003)	0.14343	0.17901	0.03615	**$0.35856**	(0.00003)	0.05100	0.17477	0.03631	**$0.26205**
Off-peak $/kWh	(0.00003)	0.05733	0.09944	0.03615	**$0.19289**	(0.00003)	0.04756	0.10602	0.03631	**$0.19076**
SOff-peak $/kWh	(0.00003)	0.01848	0.05220	0.03615	**$0.10680**	(0.00003)	0.05313	0.04726	0.03631	**$0.13667**
Mid-MW										
Max-MW	2.93	7.81			**10.74**	2.93	8.49			**$11.42**
Three Phase Adder		$1.40					$3.59			

Table 1-5
Illustrative Rates: TOU-GS-1-A Legacy

	October 2024 TOU-GS-1 Legacy Option A					Scenario 1 Proposed TOU-GS-1 Legacy Option A				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$14.24			**$14.24**		$17.09			**$17.09**
Summer season										
On-peak $/kWh	0.01404	0.34577	0.15897	0.03615	**$0.55493**	0.01404	0.31924	0.16333	0.03631	**$0.53292**
Mid-peak $/kWh	0.01404	0.21148	0.14869	0.03615	**$0.41036**	0.01404	0.15228	0.14023	0.03631	**$0.35286**
Off-peak $/kWh	0.01404	0.09679	0.14307	0.03615	**$0.29005**	0.01404	0.08433	0.12621	0.03631	**$0.26088**
On-MW										
Max-MW										
Winter season										
Mid-peak $/kWh	0.01404	0.06758	0.10551	0.03615	**$0.22328**	0.01404	0.06558	0.10479	0.03631	**$0.22072**
Off-peak $/kWh	0.01404	0.04402	0.09496	0.03615	**$0.18917**	0.01404	0.04957	0.09431	0.03631	**$0.19423**
SOff-peak $/kWh										
Mid-MW										
Max-MW										
Three Phase Adder		$1.40					$3.59			

Table 1-6
Illustrative Rates: TOU-GS-1-B Legacy

	October 2024 TOU-GS-1 Legacy Option B					Scenario 1 Proposed TOU-GS-1 Legacy Option B				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$14.24			**$14.24**		$17.09			**$17.09**
Summer season										
On-peak $/kWh	(0.00003)	0.00000	0.08671	0.03615	**$0.12283**	(0.00003)	0.00000	0.11456	0.03631	**$0.15084**
Mid-peak $/kWh	(0.00003)	0.00000	0.08110	0.03615	**$0.11722**	(0.00003)	0.00000	0.09836	0.03631	**$0.13464**
Off-peak $/kWh	(0.00003)	0.00000	0.07804	0.03615	**$0.11416**	(0.00003)	0.00000	0.08852	0.03631	**$0.12480**
On-MW			12.28		**12.28**			7.44		**$7.44**
Mid-MW			3.99		**3.99**			2.46		**$2.46**
Max-MW	2.93	22.10			**25.03**	2.93	20.59			**$23.52**
Winter season										
Mid-peak $/kWh	(0.00003)	0.00000	0.10551	0.03615	**$0.14163**	(0.00003)	0.00000	0.10477	0.03631	**$0.14105**
Off-peak $/kWh	(0.00003)	0.00000	0.09496	0.03615	**$0.13108**	(0.00003)	0.00000	0.09430	0.03631	**$0.13058**
SOff-peak $/kWh										
Mid-MW										
Max-MW	2.93	22.10			**25.03**	2.93	20.59			**$23.52**
Three Phase Adder		$1.40					$3.59			

Table 1-7
Illustrative Rates: TOU-GS-1-C Legacy

	October 2024 TOU-GS-1 Legacy Option C					Scenario 1 Proposed TOU-GS-1 Legacy Option C				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$14.24			**$14.24**		$17.09			**$17.09**
Summer season										
On-peak $/kWh	(0.00003)	0.30860	0.15897	0.03615	**$0.50369**	(0.00003)	0.27810	0.16333	0.03631	**$0.47771**
Mid-peak $/kWh	(0.00003)	0.17430	0.14869	0.03615	**$0.35911**	(0.00003)	0.12113	0.14023	0.03631	**$0.29764**
Off-peak $/kWh	(0.00003)	0.05962	0.14307	0.03615	**$0.23881**	(0.00003)	0.04319	0.12621	0.03631	**$0.20567**
On-MW										
Max-MW	2.93	7.81			**10.74**	2.93	8.49			**$11.42**
Winter season										
Mid-peak $/kWh	(0.00003)	0.03040	0.10551	0.03615	**$0.17203**	(0.00003)	0.02444	0.10479	0.03631	**$0.16551**
Off-peak $/kWh	(0.00003)	0.00684	0.09496	0.03615	**$0.13792**	(0.00003)	0.00843	0.09431	0.03631	**$0.13902**
SOff-peak $/kWh										
Mid-MW										
Max-MW	2.93	7.81			**10.74**	2.93	8.49			**$11.42**
Three Phase Adder		$1.40					$3.09			

Table 1-8
Illustrative Rates: TOU-EV-7-E

	October 2024 TOU-GS-1 TOU-EV-7- Option E					Scenario 1 Proposed TOU-EV-7 Option E				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$9.25			**$9.25**		$10.79			**$10.79**
Summer season										
On-peak $/kWh	0.01404	0.22740	0.33229	0.03615	**$0.60988**	0.01404	0.24461	0.35771	0.03615	**$0.65252**
Mid-peak $/kWh	0.01404	0.22740	0.11795	0.03615	**$0.39554**	0.01404	0.22200	0.11866	0.03615	**$0.39085**
Off-peak $/kWh	0.01404	0.09460	0.09692	0.03615	**$0.24171**	0.01404	0.11561	0.09214	0.03615	**$0.25794**
On-MW										
Mid-MW										
Max-MW										
Winter season										
Mid-peak $/kWh	0.01404	0.22740	0.17901	0.03615	**$0.45660**	0.01404	0.08493	0.17477	0.03615	**$0.30989**
Off-peak $/kWh	0.01404	0.09460	0.11403	0.03615	**$0.25882**	0.01404	0.07920	0.10692	0.03615	**$0.23631**
SOff-peak $/kWh	0.01404	0.03249	0.05220	0.03615	**$0.13488**	0.01404	0.08849	0.04726	0.03615	**$0.18594**
Mid-MW										
Max-MW										
Three Phase Adder		$1.40					$3.59			
EV Submeter Credit		($3.56)					($1.71)			

Table 1-9
Illustrative Rates: TOU-EV-7-D

	October 2024 TOU-GS-1 TOU-EV-7- Option D					Scenario 1 Proposed TOU-EV-7 Option D				
	Transmission	Base Distribution	Generation	Other	Total	Transmission	Base Distribution	Generation	Other	Total
Customer charge - $/month		$9.25			**$9.25**		$10.79			**$10.79**
Summer season										
On-peak $/kWh	0.01404	0.21820	0.33229	0.03615	**$0.60068**	0.01404	0.23997	0.35771	0.03615	**$0.64787**
Mid-peak $/kWh	0.01404	0.21820	0.11795	0.03615	**$0.38634**	0.01404	0.21736	0.11866	0.03615	**$0.38620**
Off-peak $/kWh	0.01404	0.09078	0.09692	0.03615	**$0.23789**	0.01404	0.11096	0.09214	0.03615	**$0.25329**
On-MW										
Mid-MW										
Max-MW		0.94			**0.94**		0.96			**$0.96**
Winter season										
Mid-peak $/kWh	0.01404	0.21820	0.17901	0.03615	**$0.44740**	0.01404	0.08028	0.17477	0.03615	**$0.30525**
Off-peak $/kWh	0.01404	0.09078	0.11403	0.03615	**$0.25500**	0.01404	0.07455	0.10692	0.03615	**$0.23167**
SOff-peak $/kWh	0.01404	0.03117	0.05220	0.03615	**$0.13356**	0.01404	0.08384	0.04726	0.03615	**$0.18129**
Mid-MW										
Max-MW		0.94			**0.94**		0.96			**$0.96**
Three Phase Adder		$1.40					$3.59			
EV Submeter Credit		($3.56)					($1.71)			

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

<u>MASTER METER RATE DESIGN SETTLEMENT AGREEMENT</u>

Dated: **August 12, 2025**

MASTER METER RATE DESIGN SETTLEMENT AGREEMENT

Table of Contents

Section	Page

Table of Contents (Continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

MASTER METER RATE DESIGN SETTLEMENT AGREEMENT

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), the undersigned Settling Parties in Application (A.) 24-03-019, Application of Southern California Edison Company to Establish Marginal Costs, Allocate Revenues, and Design Rates, enter into this Master Meter Rate Design Settlement Agreement (Agreement or Settlement Agreement).

1. Parties

The Parties to this Settlement Agreement are Southern California Edison Company (SCE) and the Western Manufactured Housing Communities Association (WMA) (collectively, "Master Meter Settling Parties" or "Settling Parties").

A. SCE is an investor-owned public utility and is subject to the jurisdiction of the CPUC with respect to providing electric service to its CPUC-jurisdictional retail customers.
B. WMA is a not-for-profit trade association that represents the owners of both submetered and directly-served manufactured housing communities in California.

2. Definitions

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "Base Services Charge" means the monthly fixed charge applied to customers in the Domestic Rate Group.
B. "CARE" means California Alternate Rates for Energy, which is a program that provides customers meeting a certain household income criteria a discount from SCE's otherwise applicable residential rates.
C. "Commission" or "CPUC" means the California Public Utilities Commission.
D. "DBA" means Diversity Benefit Adjustment.
E. "FERA" means the Family Electric Rate Assistance program, which provides customers meeting a certain household income and size criteria a discount from SCE's otherwise applicable residential rates.
F. "MCRA Settlement Agreement" means the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on July 1, 2025.

3. Recitals

A. In Phase 2 of SCE's 2025 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each group.
B. On March 29, 2024, SCE filed its 2025 GRC Phase 2 application (A.24-03-019) and served its initial prepared testimony regarding marginal costs, revenue allocation and rate design.
C. Protests and responses to SCE's Application were filed on May 8, 2024.
D. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling, which followed the June 3, 2024 prehearing conference.
E. Cal Advocates served its initial testimony on November 22, 2024 addressing, among other matters, SCE's residential rate design proposals.
F. Cal Advocates served amended testimony on December 27, 2024.
G. On January 8, 2025, WMA submitted prepared testimony regarding residential (master metered) rate design matters.
H. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was

held on January 3, 2025. Continuing settlement discussions occurred among the parties after that date.

I. The Master Meter Settling Parties have evaluated various residential rate design proposals in this proceeding, desire to resolve all issues related to the design of those rates,[1] and have each reached agreement as indicated in Paragraph 4 of this Agreement.

J. Appendix A to this Agreement provides a comparison of the Master Meter Settling Parties' positions related to residential rate design issues that have been resolved by this Agreement.

4. **Agreement**

In consideration of the mutual obligations, covenants and conditions contained herein, the Master Meter Settling Parties agree to the respective terms of this Agreement, which resolve all issues in this proceeding related to the design of residential master metered rates. The Settling Parties agree to the terms set forth in Paragraph 4.A, below, and Paragraphs 5-16. Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit or that its position has greater or lesser merit than the position taken by the other Settling Party to the applicable terms of the Agreement. This Agreement is subject to the express limitation on precedent described in Paragraph 11. Unless provided otherwise, such as in Paragraph 11, this Agreement and its terms are intended to remain in effect from the date rate changes are implemented as a result of a CPUC decision in this proceeding.

A. **Master Meter Rate Design**

1) **Illustrative Rates**

The Master Meter Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the residential class's share of SCE's consolidated 2024 revenue requirement of $17,466 million described in more detail in Paragraph 4.B.1 of the MCRA

---

[1] Except for (1) PRIME Plus Rate Proposal, (2) TURN's baseline allowance proposal and (3) SCE CARE discount proposal.

Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the MCRA Settlement Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

2) Master Meter Rates

a) Description of Master Metered Schedules

SCE currently offers four master metered schedules that include the same set of charges as Schedule D: Schedules DM, DMS-1, DMS-2, and DMS-3. Under these Schedules, service is supplied by SCE to more than one residence through a master meter. If residences are sub-metered, tenants are required to be billed by the owner or property management for their usage under Schedule D, Schedule D-CARE, or Schedule D-FERA. The charges in the master metered electric bill are adjusted to reflect the specific cost characteristics of master metered accounts.

b) Schedules DM, DMS-1, DMS-2, DMS-3

Settling Parties agree to apply the DBA to DMS-3 using the DBA methodology for DMS-2. This treatment is consistent with the treatment for DM and DMS-1 customers. The Settling Parties also agree to a submetering discount of $0.426 per-space-day.[2] No structural or eligibility changes are being made to Schedules DM, DMS-1, and DMS-2; however, Schedule DMS-1 and DMS-2 are updated to reflect the submetering discounts set forth below.

c) Sub-metering and Total Discount

Customers served on Schedule DMS-2 receive a total discount for providing sub-metered service, which is comprised of a submetering discount that is reduced by a DBA. The discount for customers who provide sub-metered electric service on Schedule DMS-2 is shown below in Table 4-1. Using the methodology described in Exhibit SCE-04A and based upon the revenue requirement and the residential rate structures proposed in this Agreement, the estimated DBA is also shown in Table 4-1 below.

---

[2] The submetering discount reflects the cost-of-service and line loss discount components.

A final DBA will be established upon implementation of rates in the Settlement Agreement based on the methodology referenced above and the then current revenue requirements and residential rates. Once set, the DBA will remain fixed over the attrition years. Settling Parties will have the option to review the DBA and propose changes to the DBA should significant changes in the residential tier rate structure emerge from Rulemaking 22-07-005 or changes to the methodology used to determine the Baseline Allowance be adopted in any proceeding.

The Basic Charge adjustments and the DBAs for Schedules DM shall be determined in the same manner as they are today. The Base Services Charges and the DBAs for Schedule DMS-1 shall be determined in the same manner as the Base Services Charge and DBA are determined for Schedule DMS-2 when this Agreement is implemented. The cost-of-service discount provided to customers served on Schedule DMS-1 shall initially be set at a level that maintains the 28% percent difference between the discounts for Schedules DMS-1 and DMS-2. Submetering discounts do not apply to Schedules DM and DMS-3.

Proposed Master Meter AdjustmentsTable

Line No.	Rate Schedule	Adjustments	Proposed Settlement $/Space
1	DM	Diversity Benefit Adjustment	-$0.059
2	DMS-1	Diversity Benefit Adjustment	-$0.059
3		Discount: Cost of Service	$0.118
4		Line Loss	$0.000
5		Submetering Discount	$0.118
6		Total Discount	$0.059
7	DMS-2	Diversity Benefit Adjustment	-$0.059
8		Discount: Cost of Service	$0.420
9		Line Loss	$0.006
10		Submetering Discount	$0.426
11		Total Discount	$0.367
12	DMS-3	Diversity Benefit Adjustment	-$0.059
Note: The Base Services Charge will be paid by all tenants and has been converted to a per day value.			

d) <u>Further Agreement on Schedule DM, DMS-1, DMS-2 and DMS-3</u>

Other than as noted above, the Master Meter Settling Parties agree that this Settlement Agreement resolves all issues relating to SCE's master meter rate schedules and tariff language.

5. **Implementation of Settlement Agreement**

It is the intent of the Master Meter Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1 of 2026.

6. **Incorporation of Complete Agreement**

The Master Meter Settling Parties intend the terms described at the outset of Paragraph 4.A. to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of the applicable terms of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Master Meter Settling Parties agree to oppose any modification in each of the applicable terms of this Agreement not agreed to by all Settling Parties who agreed on those terms. If the Commission does not approve this Agreement without modification, the Settling Parties to whom that change is relevant in the Agreement shall promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties as set forth in Section 9 below, and shall promptly seek Commission approval of the resolution so achieved.

7. **Record Evidence**

The Master Meter Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

8. **Signature Date**

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

9. **Regulatory Approval**

The Master Meter Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's 2025 GRC.

The Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Master Meter Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest. Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties for the respective settlement within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Master Meter Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

10. <u>Compromise of Disputed Claims</u>

This Settlement Agreement represents a compromise of disputed claims between the Master Meter Settling Parties for each of the terms to which they have agreed. The Settling Parties have each independently reached an agreement on the issues related to the design of those rates after taking into account the possibility that each Settling Party may or may not prevail on any given issue. The Master Meter Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

11. <u>Non-Precedential</u>

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before this Commission.

The Master Meter Settling Parties expressly recognize that each Settling Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2029 General Rate Case or in another proceeding if invited by the Commission. Barring Commission-ordered modifications to this Settlement Agreement, the Settling Parties will support the continued applicability of Section 4 until the date on which SCE's tariffs implementing its 2025 GRC Phase 2 becomes effective.

12. Previous Communications

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to residential master metered rate design issues. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

13. Non-Waiver

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

14. Effect of Subject Headings

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

15. Governing Law

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. Number of Originals

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: August 12, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Michael Backstrom

By: Michael Backstrom
Title: Senior Vice President, Regulatory Affairs

Dated: August 12, 2025

WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION

/s/ Edward G. Poole

By: Edward G. Poole
Title: Attorney

Appendix A

Comparison of Party Positions on Master Meter Rate Design Matters and Settlement

Comparison of Parties' Positions
Master Meter Rate Design Issues

Issue	SCE	WMA	Settled Position
Master Meter Discount / Submetering	Master Meter sub-metering discount be based on Single Family Underground-configuration; Total discount = $0.367/unit/day.	Final decision should include adoption of a methodology for calculating master meter discounts subsequent to implementation of fixed charges. Supports SCE's proposed cost of service and line loss components. Also, supports total discount of $0.367	Use Single-family cost. Sub metering (Cost of Service) discount calculated to $0.426 unit/day. Total discount = $0.367 unit/day. SCE to maintain the DBA during attrition years.

Appendix B

Illustrative Master Meter Rates

Table 1
Illustrative Rates for DM & DMS-2

	October 2024 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
DM									
Diversity Adjustment - $/unit/day	0.084		0.084	0.059		0.059	-29.8%		-29.8%
Agricultural Employee Housing Discount - %	-29.00%		-29.00%	-28.60%		-28.60%	1.4%		1.4%
DMS-2									
Submeter Discount - $/unit/day	(0.303)		(0.303)	(0.426)		(0.426)	40.6%		40.6%
Diversity Adjustment - $/unit/day	0.084		0.084	0.059		0.059	-29.8%		-29.8%
Basic Charge Adjustment - $/unit/day	0.024		0.024	0.031		0.031	29.2%		29.2%
Basic Charge Adjustment CARE - $/unit/day	0.018		0.018	0.025		0.025	38.9%		38.9%
Basic Charge Adjustment FERA - $/unit/day	0.020		0.020	0.025		0.025	25.0%		25.0%

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

<u>RESIDENTIAL RATE DESIGN SETTLEMENT AGREEMENT</u>

Dated: **August 12, 2025**

RESIDENTIAL RATE DESIGN SETTLEMENT AGREEMENT

Table of Contents

Section	**Page**

RESIDENTIAL RATE DESIGN SETTLEMENT AGREEMENT

Table of Contents (Continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

RESIDENTIAL RATE DESIGN SETTLEMENT AGREEMENT

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), the undersigned Settling Parties in Application (A.) 24-03-019, Application of Southern California Edison Company to Establish Marginal Costs, Allocate Revenues, and Design Rates, enter into this Residential Rate Design Settlement Agreement (Agreement or Settlement Agreement).

1. Parties

The Parties to this Settlement Agreement are Southern California Edison Company (SCE), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), The Utility Reform Network (TURN), Solar Energy Industries Association (SEIA), and the Center for Accessible Technology (CforAT), (collectively, "Residential Settling Parties" or "Settling Parties").

A. SCE is an investor-owned public utility and is subject to the jurisdiction of the CPUC with respect to providing electric service to its CPUC-jurisdictional retail customers.
B. Cal Advocates represents the interests of public utility customers. Its goal is to obtain the lowest possible rate for service consistent with safe, reliable service, and the State's environmental goals. Pursuant to California Public Utilities Code Section 309.5(a), Cal Advocates is directed to primarily consider the interests of residential and small commercial customers in revenue allocation and rate design matters.

C. TURN is an independent, non-profit consumer advocacy organization that represents the interests of residential and small commercial utility customers.

D. SEIA is the national trade association of the solar and storage industries. Through outreach and education, SEIA and its over 1,200 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy and storage.

E. CforAT is the leading organization representing the interests of utility customers with disabilities and medical needs.

2. Definitions

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "Base Rate" means the rate option (*e.g.*, TOU-D-4-9PM) in a rate group (*e.g.*, Residential) against which all other options within the rate group are designed to be revenue neutral. For the Residential class, the Base Rate also serves as the Default Rate option.

B. "Base Services Charge" means the monthly fixed charge applied to customers in the Domestic Rate Group.

C. "CARE" means California Alternate Rates for Energy, which is a program that provides customers meeting a certain household income criteria a discount from SCE's otherwise applicable residential rates.

D. "Commission" or "CPUC" means the California Public Utilities Commission.

E. "Energy Charges" mean the dollar-per-kilowatt-hour (kWh) charges that recover (1) generation services revenues; (2) delivery services revenues not recovered via the Base Services Charge; and, (3) other delivery services revenues for public purpose programs (including Energy Efficiency and CARE), New System Generation Service (NSGS), Transmission, Nuclear Decommissioning, CARE balancing account, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and CPUC reimbursement fees. Energy Charges are designed to provide a price signal consistent with marginal cost differentials in TOU energy rates, where TOU energy rates apply to a specific schedule.

F. “Energy Rates” means the volumetric rates paid by residential customers who are served on SCE’s residential rate schedules.

G. “EPMC” means equal percent of marginal cost. Because marginal cost revenues do not equal the utility’s revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group’s percentage share of marginal cost revenue responsibility by function (*i.e.*, separately for generation costs, and for combined distribution and customer costs). The marginal cost revenues of all rate groups are scaled using the same EPMC multipliers – one multiplier for generation and one for distribution – so that total system generation and distribution revenues equal the Commission-approved revenue requirements.

H. “FERA” means the Family Electric Rate Assistance program, which provides customers meeting a certain household income and size criteria a discount from SCE’s otherwise applicable residential rates.

I. “FERC” means the Federal Energy Regulatory Commission.

J. “Functional SAPC Allocation” means allocation of SCE’s revenue requirement to each of SCE’s rate groups based on the system average percentage change (“SAPC”) for the particular function, *e.g.*, generation, or distribution and customer costs. In addition, this would include adjustments of FERC-jurisdictional transmission revenues as authorized by formula rates or otherwise.

K. “MCRA Settlement Agreement” means the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on July 1, 2025.

L. “NCO” means New Customer Only, and is a method use to derive marginal customer access costs, taking into account the capital cost of adding new customers only and other operations and maintenance (O&M) costs.

M. “OAT” means “Otherwise Applicable Tariff.”

N. “PLRF” means “Peak Load Risk Factor,” and represents the methodology used to assess capacity constraints on the distribution system and to assign peak-capacity-related design demand marginal costs to TOU periods.

O. "RECC," or "Real Economic Carrying Charge," means the percentage of a utility investment which corresponds to the first year of a stream of numbers where the net present value of revenue requirements of a utility investment is adjusted to rise at the rate of inflation over the life of the investment. It also represents the value of deferring a utility investment by a year.

P. "TOU" means time-of-use. These are the time periods established for the provision of electric service in which Demand Charges and/or Energy Charges may vary across time periods in relation to the cost of service, as adopted in Decision (D.)18-07-006.[1]

Q. "TOU Period Rate Differentials" means the ratio between the on- or mid-peak rates compared to the lowest or off-peak rates. For instance, the TOU period differential between an on-peak rate that is 40 cents per kWh and an off-peak rate of 20 cents per kWh is 2:1, where the on-peak rate is 2 times higher than the off-peak rate.

3. Recitals

A. In Phase 2 of SCE's 2025 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each group.

B. On March 29, 2024, SCE filed its 2025 GRC Phase 2 application (A.24-03-019) and served its initial prepared testimony regarding marginal costs, revenue allocation and rate design.

C. Protests and responses to SCE's Application were filed on May 8, 2024.

D. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling, which followed the June 3, 2024 prehearing conference.

E. Cal Advocates served its initial testimony on November 22, 2024 addressing, among other matters, SCE's residential and small commercial rate design proposals.

F. Cal Advocates served amended testimony on December 27, 2024.

G. On January 8, 2025, TURN, SBUA, SEIA, WMA, and CforAT submitted prepared testimony regarding residential and/or small commercial rate design matters.

---

1 *See* SCE's Rate Design Window Application 16-09-003 (2016 RDW).

H. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on January 3, 2025. Continuing settlement discussions occurred among the parties after that date.

I. The Residential Settling Parties have evaluated various residential rate design proposals in this proceeding, desire to resolve all issues related to the design of those rates,[2] and have each reached agreement as indicated in Paragraph 4 of this Agreement.

J. Appendix A to this Agreement provides a comparison of the Residential Settling Parties' positions related to residential rate design issues that have been resolved by this Agreement.

4. **Agreement**

In consideration of the mutual obligations, covenants and conditions contained herein, the Residential Settling Parties agree to the respective terms of this Agreement, which resolve all issues in this proceeding related to the design of residential rates with the exception of the following: 1) TURN's Baseline Allowances Proposal, 2) SCE's PRIME Plus Proposal, and 3) the CARE Discount Proposal, which was withdrawn by SCE.[3] The Residential Settling Parties agree to the terms set forth in Paragraph 4.A, below, and Paragraphs 5-16. Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit or that its position has greater or lesser merit than the position taken by any other Settling Party to the applicable terms of the Agreement. This Agreement is subject to the express limitation on precedent described in Paragraph 11. Unless provided otherwise, such as in Paragraph 11, this Agreement and its terms are intended to remain in effect from the date rate changes are implemented as a result of a CPUC decision in this proceeding.

---

[2] Except for (1) PRIME Plus Rate Proposal, (2) TURN's baseline allowance proposal and (3) SCE CARE discount proposal.

[3] *See* Ex. SCE-07, p. 2-3 (noting withdrawal of SCE's CARE discount proposal).

A. Residential Rate Design

1) Illustrative Rates

The Residential Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the residential class's share of SCE's consolidated 2024 revenue requirement of $17,466 million described in more detail in Paragraph 4.B.1 of the MCRA Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the MCRA Settlement Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

2) Baseline Regions

SCE's Baseline Regions are closely aligned to the California Energy Commission (CEC) climate zones that were in place in 2009 and were approved in D.09-08-028. Technological improvements in geographic information system (GIS) mapping over the years can in some instances cause slight shifting of Baseline Region boundaries, however, SCE's Baseline Regions are fixed to the KMZ vectors that were in place in 2009.[4]

3) Fixed Charges and Minimum Bills

SCE's residential rate designs are aligned and comply with D.24-05-028. Per the Decision, all rate proposals include fixed charges, or Base Services Charges of $24.15 per month for Non-CARE customers, $12 per month for FERA customers and those living in deed restricted affordable housing, and $6 per month for CARE customers.
Upon implementation of the Base Services Charge as approved by the Decision, minimum bills will be eliminated.

4) TOU Default Rate

SCE's TOU-D-4-9PM is the default rate for purposes of revenue allocation and rate design. The effective CARE and FERA discounts will be calculated

---

[4] KMZ (Keyhole Markup Language zipped) is a file that stores maps locations viewable in Google Earth.

consistent with D.24-05-028, where the statutory and regulatory rate exclusions are removed from the non-CARE bill before application of the single line-item CARE and FERA discounts are applied to customer bills.

5) Additional Non-TOU Rate Schedules Available to Residential Customers [5]

a) Schedule D

No structural or eligibility changes are made to Schedule D.

b) Schedule D-SDP

No structural or eligibility changes are made to Schedule D-SDP.

c) Schedule D-CARE

No structural or eligibility changes are made to Schedule D-CARE. SCE will continue to offer the CARE discount in the form of a line-item credit approved in D.18-12-004 and the calculation methodology approved in D.24-05-028.

d) Medical Baseline

No structural changes are made to the existing medical baseline provisions currently in place, which are applicable to any tiered rate, as well as eligible non-tiered rates (i.e., TOU-D PRIME). SCE will continue to apply a medical line-item discount to eligible customer bills. The Parties confirm in this Settlement Agreement that PRIME remains the only non-tiered option and the discount will continue to be available to PRIME customers, as well as PRIME Plus customers should the PRIME Plus proposal be approved by the Commission.

i. Medical Line-Item Discount Equivalence for Non-Tiered Residential Rates

A medical line-item discount of 11% shall be offered to eligible customers, including customers enrolled in the Self Generation Incentive Program, selecting

[5] Metered multi-family non-TOU tiered rate schedules are addressed in the Master-Meter Adjustments section.

residential non-tiered rate schedules to provide these customers with the benefit of the existing Medical Baseline subsidy on rates that do not have a baseline credit structure.[6] The medical line-item discount will be applied to currently available non-tiered rate options.[7] The credit amount was calculated by comparing the total bills of customers receiving the medical baseline benefit on tiered rates to those same bills without the discount. The requirement for an 11% discount for customers who are enrolled in Medical Baseline will also apply to any new non-tiered rate options that are created prior to when the next General Rate Case Phase 2 is resolved.

Customers receiving the medical discount on a non-tiered rate would also receive all non-financial benefits provided to Medical Baseline customers, including enhanced notice in advance of a de-energization event.

Eligible medical baseline customers would have a choice of how to receive their benefits, either by: (a) remaining on a tiered rate and receiving the additional medical baseline allowance, along with the Wildfire Non-bypassable Fund exemption; or (b) moving to a non-tiered TOU rate and receiving the 11 percent line-item discount and the Wildfire Non-bypassable Fund exemption. For eligible customers taking service from a Community Choice Aggregator, or other unbundled service, SCE will determine the amount of the discount based on total bundled charges.

e) Schedule D-FERA

No structural or eligibility changes are made to Schedule D-FERA. The FERA discount for eligible household will continue to be set at 18 percent.

f) Schedules DE

No structural or eligibility changes are made to Schedule DE.

6) TOU Rates

In addition to the tiered rate schedules described above, SCE will also offer various TOU rates for residential customers.

---

[6] The baseline credit is the $ per kWh difference from tier 2 to tier 1 rates ($/kWh). Therefore, rates that have a baseline credit are, by definition, tiered rates.

[7] TOU-D-PRIME is currently the only available non-tiered rate option that will include the medical line-item upon implementation of this Residential Settlement Agreement.

a) Schedule TOU-D-4-9pm and TOU-D-5-8pm

Schedule TOU-D will continue to include two options, 4-9PM and 5-8PM, with 4-9PM being the TOU default rate as described in Paragraph 4.A.5 above. These rates include a five-hour weekday on-peak period from 4 p.m. to 9 p.m. and a three-hour on-peak period from 5 p.m. to 8 p.m., respectively. Agreed upon changes are as described below.

i. Schedule TOU-D-4-9pm TOU Period Differentials

TOU-D-4-9pm shall maintain the existing seasonal differential of 1 cent per kWh and move the TOU Period Rate Differentials to 80% of marginal cost differential over a 4-year transition period. In each year of the transitory period, the TOU Period Rate differentials will be set to move 1/4 of the required adjustment to reach 80% of the marginal cost TOU Period differential by the end of the 4-year period. The adjustments will be made on October 1st of each year concurrent with SCE's seasonal rate change, starting October 1, 2026, then on October 1, 2027, October 1, 2028, and concluding on October 1, 2029.

ii. Schedule TOU-D-5-8pm TOU Period Differentials

TOU-D-5-8pm shall see an increase in the seasonal differential from 1 cent per kWh to 3 cents per kWh and move the TOU Period Rate Differentials to 80% of marginal cost differential over a 4-year transition period. In each year of the transitory period, the TOU Period Rate Differentials will be set to move 1/4 of the required adjustment to reach 80% of the marginal cost TOU Period Differential by the end of the 4-year period. The adjustments will be made on October 1st of each year concurrent with SCE's seasonal rate change, starting October 1, 2026, then on October 1, 2027, October 1, 2028, and concluding on October 1, 2029.

b) TOU-D-PRIME

Schedule TOU-D-PRIME is an optional TOU rate intended for higher usage customers and customers who have load-modifying electric technologies, including those customers who have electric vehicles (EVs), behind-the-meter (BTM) energy storage systems and/or electric heat pump systems for water or space heating. TOU-D-PRIME also serves as the default rate for customers newly adopting renewable energy technologies.

TOU-D-PRIME includes the following key rate design features:

- Introduce a winter Super off-peak (SOP) rate factor to provide a more meaningful super-off-peak period rate.
- No baseline credit; and
- A Base Services Charge consistent with D.24-05-028.

i. TOU-D-PRIME TOU Period Differentials

TOU-D-PRIME shall see an increase in the seasonal differential from 2.4 cents per kWh to 6 cents per kWh. In addition, the TOU Period Rate Differentials in TOU-D-PRIME will move to 100% of marginal cost differential over a 4-year transition period. In each year of the transition period, the TOU Period Rate Differentials will be set to move 1/4 of the required adjustment so that 100% of the marginal cost TOU Period Differential is reached at the end of the 4-year period. The adjustments will be made on October 1st of each year concurrent with SCE's seasonal rate change, starting October 1, 2026, then on October 1, 2027, October 1, 2028, and concluding on October 1, 2029.

Additionally, The Settling Parties recognize that the Commission has expressed the intent to examine rate differentials between TOU periods for the residential rates of the Investor-Owned Utilities, including SCE, as part of Rulemaking 22-07-005 or a successor proceeding. If such examination does occur prior to SCE filing its next GRC Phase 2 Application, then each Settling Party reserves the right to take positions on the rate differentials between TOU periods for residential rates that are not consistent with the differentials agreed to in this Settlement Agreement.

ii. Electric Vehicle Charging

A rider option under TOU-D-PRIME will continue to be offered to customers who have separately metering electric vehicle charging. This rate rider provides a monthly credit to be applied to the customer charge to make the separately metered TOU-D-PRIME customer charge consistent with the previously offered separately metered Schedule TOU-EV-1[8] monthly meter charge. The reduced customer charge is intended to recover the cost

---

[8] Schedule TOU-EV-1 is a discontinued rate option for customers who have electric vehicle charging stations with a dedicated meter.

of the additional meter, while recognizing that the service point and other associated facility costs are recovered through the customer charge of the customer's primary meter.

7) Heat Pump Water Heater Incremental Baseline Allowance

a) Customer Eligibility

To encourage adoption and usage of heat pump water heater (HPWH) technology, an incremental baseline allowance will continue to be offered to qualified customers on Schedule D, TOU-D-4-9PM and TOU-D-5-8PM, including those already receiving an all-electric allowance. The purpose of this allowance is to cover, for the average customer, the net energy bill increases as a result of switching from a typical natural gas water heater to a typical electric HPWH.

b) Customer Verification

In order to receive the HPWH incremental baseline allowance, customers must either attest to having HPWH technology or SCE must have a record of the customer having a HPWH. SCE shall continue track and report on the number of customers who attest to having HPWH or have a record and receiving the incremental baseline allowance. This information will be included in SCE's next (2029) GRC Phase 2 Application.

c) Incremental Baseline Allowance Amount

The Parties agree that the following incremental baseline allowances shall be provided to eligible customers with HPWHs.

Incremental Baseline Allowances Table

	Summer kWh per Day	*Winter kWh per Day*
Basic	*1.9*	*2.6*
All Electric	*1.9*	*3*

d) Evaluation in SCE's Next GRC Phase 2

In its next GRC Phase 2, SCE commits to evaluating whether the incremental HPWH allowance that is implemented was appropriate. This evaluation will include examining uptake and actual estimated changes in usage for participating customers. SCE will include the results of this evaluation in its testimony, as well as whether SCE recommends making any changes to the incremental HPWH allowance calculation, amount, mechanism, or implementation.

5. Implementation of Settlement Agreement

It is the intent of the Residential Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1 of 2026.

5. Incorporation of Complete Agreement

The Residential Settling Parties intend the terms described at the outset of Paragraph 4.A. to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Residential Settling Parties acknowledge that changes, concessions, or compromises by any Settling Party or Settling Parties in one section of the applicable terms of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Residential Settling Parties agree to oppose any modification in each of the applicable terms of this Agreement not agreed to by all Settling Parties who agreed on those terms. If the Commission does not approve this Agreement without modification, the Settling Parties to whom that change is relevant in the Agreement shall promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties as set forth in Section 9 below, and shall promptly seek Commission approval of the resolution so achieved.

5. Record Evidence

The Residential Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

5. Signature Date

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

5. Regulatory Approval

The Residential Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's 2025 GRC.

The Residential Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Residential Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest. Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Residential Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties for the respective settlement within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Residential Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

10. Compromise of Disputed Claims

This Settlement Agreement represents a compromise of disputed claims between the Residential Settling Parties for each of the terms to which they have agreed. The Residential Settling Parties have each independently reached an agreement on the issues related to the design of those rates after taking into account the possibility that each Party may or may not prevail on any given issue. The Residential Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

11. Non-Precedential

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before this Commission.

The Residential Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2025 General Rate Case or in another proceeding if invited by the Commission. Barring Commission-ordered modifications to this Settlement Agreement, the Settling Parties will support the continued applicability of Section 4 until the date on which SCE's tariffs implementing its 2025 GRC Phase 2 becomes effective.

12. Previous Communications

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to residential rate design issues. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

13. Non-Waiver

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

14. Effect of Subject Headings

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

15. Governing Law

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. Number of Originals

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: August 12, 2025 SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Michael Backstrom

By: Michael Backstrom
Title: Senior Vice President, Regulatory Affairs

Dated: August __, 2025 PUBLIC ADVOCATES OFFICE

____

By: Michael Campbell
Title: Deputy Director

Dated: August 12, 2025 THE UTILITY REFORM NETWORK

/s/ David Cheng

By: David Cheng
Title: Staff Attorney

Dated: August 12, 2025 SOLAR ENERGY INDUSTRIES ASSOCIATION

/s/ Jeanne Armstrong

By: Jeanne Armstrong
Title: Senior Regulatory Counsel

15. Governing Law

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. Number of Originals

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: August __, 2025 SOUTHERN CALIFORNIA EDISON COMPANY

____
By: Michael Backstrom
Title: Senior Vice President, Regulatory Affairs

Dated: August 7, 2025 PUBLIC ADVOCATES OFFICE

____
By: Michael Campbell
Title: Deputy Director

Dated: August __, 2025 THE UTILITY REFORM NETWORK

____
By: David Cheng
Title: Staff Attorney

Dated: August __, 2025 SOLAR ENERGY INDUSTRIES ASSOCIATION

____
By: Jeanne Armstrong
Title: Senior Regulatory Counsel

Dated: August 12, 2025

CENTER FOR ACCESSIBLE TECHNOLOGY

/s/ Melissa Kasnitz

By: Melissa Kasnitz
Title: Legal Director

Appendix A

Comparison of Party Positions on Residential Rate Design Matters and Settlement

Comparison of Parties' Positions
Residential Rate Design Issues

Issue	SCE	Cal Advocates	TURN	SEIA	CforAT	WMA	Settled Position
Tiered Rates / TOU-D-4-9PM / TOU-D-5-8PM	Maintain Tiered Rate differentials Maintain TOU Rate differentials Increase seasonal differentials for 5-8PM	Support maintaining current tiered and TOU rate differentials		SEIA supports SCE's proposed increase in seasonal differentials and proposed increases in TOU Period Rate Differentials of 80 percent of MC over four year period			Maintain seasonal differentials at 1 cent per kWh for 4-9PM, however, move towards TOU Period Differentials of 80% of MC over a four year period Increase seasonal differentials for 5-8PM to 3 cents per kWh (80% to MC over a four-yr period)
TOU-D-PRIME Rate Design	Increase seasonal differential from2.4 cents per kWh to 6 cents per kWh The rate option includes a fixed basic charge allows for lower super-off-peak and off-peak rates	Reject proposal to increase to seasonal differentials		SEIA supports SCE's proposed increase in seasonal differentials and proposed an increase in TOU Period Rate Differentials of 80 percent of MC over four year period			Increase seasonal differential to 6 cents per kWh moving towards TOU Period Rate Differential of 100% of MC over a four year period
Heat Pump Water Heater (HPWH)	Maintain incremental baseline allowance for HPWH on TOU-D-4-9 & TOU-D-5-8	Supports SCE's proposal					Maintains incremental baseline to be offered to qualified customers on TOU-D-4-9PM and TOU-D-5-8PM

Appendix B

Illustrative Residential Rates

Table 1-1
Illustrative Rates for Tiered

	Tier Rate							
	Current Rate With Basic Service Charge				Proposed Rate With Basic Service Charge			
	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total
Tier 1	0.15560	0.16057	0.12282	0.28339	0.16345	0.17517	0.11748	0.29265
Tier 2	0.15560	0.25150	0.12282	0.37432	0.16345	0.26004	0.11748	0.37752
Tier 1 BSC		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15

Table 1-2
Illustrative Rates for TOU-D-4-9PM

	TOU - 4 p.m. to 9 p.m.							
	Current Rate With Basic Service Charge				Proposed Rate Year 4: October 2029			
	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total
Summer On	0.25345	0.29218	0.25144	0.54362	0.29757	0.34071	0.32635	0.66707
Summer Mid	0.25345	0.29218	0.13995	0.43213	0.29272	0.33587	0.08562	0.42149
Summer Off	0.20151	0.24024	0.08209	0.32233	0.18621	0.22936	0.06000	0.28936
Winter Mid	0.25345	0.29218	0.18204	0.47422	0.22558	0.26873	0.23640	0.50513
Winter Off	0.20151	0.24024	0.10783	0.34807	0.20854	0.25169	0.09246	0.34415
Winter Super-Off	0.18282	0.22155	0.09024	0.31179	0.21172	0.25487	0.04513	0.30000
Baseline Credit				(0.09092)				(0.08487)
Tier 1 BSC		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15
Seasonal Average Rate								
Summer Average Rate	0.21751		0.12392	0.38016	0.22006		0.11976	0.38297
Winter Average Rate	0.20940		0.12200	0.37013	0.21405		0.11577	0.37297
Seasonal Delta	0.00810		0.00193	**0.01003**	0.00601		0.00399	**0.01000**
TOU Ratios								
Summer On	1.25775		3.06298		1.59798		5.43947	
Summer Mid	1.25775		1.70484		1.57196		1.42705	
Summer Off	1.00000		1.00000		1.00000		1.00000	
Winter Mid	1.38634		2.01729		1.06548		5.23849	
Winter Off	1.10223		1.19492		0.98498		2.04900	
Winter Super-Off	1.00000		1.00000		1.00000		1.00000	

	Proposed Rate Glidepath TOU - 4 p.m. to 9 p.m.															
	Year 1: October 2026				Year 2: October 2027				Year 3: October 2028				Year 4: October 2029			
	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total
Summer On	0.26742	0.31057	0.26850	0.57907	0.27793	0.32108	0.29046	0.61154	0.28796	0.33111	0.30957	0.64069	0.29757	0.34071	0.32635	0.66707
Summer Mid	0.26613	0.30928	0.12007	0.42935	0.27539	0.31854	0.10699	0.42553	0.28425	0.32740	0.09561	0.42301	0.29272	0.33587	0.08562	0.42149
Summer Off	0.19915	0.24230	0.07342	0.31572	0.19464	0.23779	0.06832	0.30612	0.19034	0.23348	0.06389	0.29738	0.18621	0.22936	0.06000	0.28936
Winter Mid	0.25146	0.29461	0.19741	0.49202	0.24337	0.28652	0.21443	0.50095	0.23476	0.27791	0.22689	0.50480	0.22558	0.26873	0.23640	0.50513
Winter Off	0.20656	0.24971	0.09851	0.34822	0.20718	0.25033	0.09587	0.34620	0.20784	0.25099	0.09394	0.34493	0.20854	0.25169	0.09246	0.34415
Winter Super-Off	0.19252	0.23567	0.06994	0.30561	0.19852	0.24167	0.05911	0.30078	0.20491	0.24806	0.05118	0.29924	0.21172	0.25487	0.04513	0.30000
Baseline Credit				(0.08487)				(0.08487)				(0.08487)				(0.08487)
Tier 1 BSC		6.00		6.00		6.00		6.00		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15		24.15		24.15		24.15		24.15
Seasonal Average Rate																
Summer Average Rate	0.22006		0.11976	0.38297	0.22006		0.11976	0.38297	0.22006		0.11976	0.38297	0.22006		0.11976	0.38297
Winter Average Rate	0.21405		0.11577	0.37297	0.21405		0.11577	0.37297	0.21405		0.11577	0.37297	0.21405		0.11577	0.37297
Seasonal Delta	0.00601		0.00399	**0.01000**	0.00601		0.00399	**0.01000**	0.00601		0.00399	**0.01000**	0.00601		0.00399	**0.01000**
TOU Ratios																
Summer On	1.34281		3.65710		1.42787		4.25123		1.51292		4.84535		1.59798		5.43947	
Summer Mid	1.33631		1.63539		1.41486		1.56594		1.49341		1.49650		1.57196		1.42705	
Summer Off	1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000	
Winter Mid	1.30612		2.82259		1.22591		3.62789		1.14569		4.43319		1.06548		5.23849	
Winter Off	1.07292		1.40844		1.04360		1.62196		1.01429		1.83548		0.98498		2.04900	
Winter Super-Off	1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000	

Table 1-3
Illustrative Rates for TOU-D-5-8PM

	TOU - 5 p.m. to 8 p.m.							
	Current Rate With Basic Service Charge				Proposed Rate Year 4: October 2029			
		Delivery				Delivery		
	Dist	Total	Gen	Total	Dist	Total	Gen	Total
Summer On	0.25956	0.29829	0.39299	0.69128	0.33240	0.37554	0.40956	0.78511
Summer Mid	0.25956	0.29829	0.20700	0.50529	0.22240	0.26555	0.22916	0.49471
Summer Off	0.20956	0.24829	0.07270	0.32099	0.20803	0.25118	0.07639	0.32757
Winter Mid	0.25956	0.29829	0.26582	0.56411	0.22250	0.26565	0.23505	0.50070
Winter Off	0.20956	0.24829	0.10608	0.35437	0.20477	0.24792	0.11070	0.35862
Winter Super-Off	0.18248	0.22121	0.08073	0.30194	0.21462	0.25776	0.05373	0.31150
Baseline Credit				(0.09093)				(0.08487)
Tier 1 BSC		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15
Seasonal Average Rate								
Summer Average Rate	0.21900		0.12234	0.38008	0.22465		0.12713	0.39494
Winter Average Rate	0.20817		0.12318	0.37007	0.21096		0.11083	0.36494
Seasonal Delta	0.01084		(0.00083)	**0.01000**	0.01370		0.01630	**0.03000**
TOU Ratios								
Summer On	1.23839		5.33992		1.59781		5.36168	
Summer Mid	1.23839		2.81270		1.06908		3.00000	
Summer Off	0.99983		0.98784		1.00000		1.00000	
Winter Mid	1.33741		3.85424		1.03674		4.37429	
Winter Off	1.07978		1.53810		0.95413		2.06018	
Winter Super-Off	0.94024		1.17054		1.00000		1.00000	

	Proposed Rate Glidepath TOU - 5 p.m. to 8 p.m.							
	Year 1: October 2026				Year 2: October 2027			
		Delivery				Delivery		
	Dist	Total	Gen	Total	Dist	Total	Gen	Total
Summer On	0.27843	0.32157	0.39702	0.71859	0.29650	0.33964	0.40136	0.74100
Summer Mid	0.25072	0.29387	0.21179	0.50566	0.24123	0.28438	0.21682	0.50120
Summer Off	0.20959	0.25274	0.07359	0.32634	0.20906	0.25221	0.07455	0.32676
Winter Mid	0.25734	0.30049	0.24574	0.54623	0.24642	0.28957	0.24197	0.53154
Winter Off	0.21345	0.25660	0.10349	0.36009	0.21069	0.25384	0.10649	0.36033
Winter Super-Off	0.19408	0.23723	0.06897	0.30619	0.20041	0.24356	0.06312	0.30668
Baseline Credit				(0.08487)				(0.08487)
Tier 1 BSC		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15
Seasonal Average Rate								
Summer Average Rate	0.22060		0.12231	0.38605	0.22195		0.12392	0.38902
Winter Average Rate	0.21375		0.11416	0.37105	0.21282		0.11305	0.36902
Seasonal Delta	0.00685		0.00815	**0.01500**	0.00913		0.01087	**0.02000**
TOU Ratios								
Summer On	1.32840		5.39465		1.41820		5.38366	
Summer Mid	1.19622		2.87785		1.15384		2.90839	
Summer Off	1.00000		1.00000		1.00000		1.00000	
Winter Mid	1.32599		3.56310		1.22957		3.83350	
Winter Off	1.09983		1.50055		1.05127		1.68710	
Winter Super-Off	1.00000		1.00000		1.00000		1.00000	

	Year 3: October 2028				Year 4: October 2029			
		Delivery				Delivery		
	Dist	Total	Gen	Total	Dist	Total	Gen	Total
Summer On	0.31449	0.35763	0.40568	0.76331	0.33240	0.37554	0.40956	0.78511
Summer Mid	0.23179	0.27494	0.22191	0.49685	0.22240	0.26555	0.22916	0.49471
Summer Off	0.20854	0.25169	0.07551	0.32720	0.20803	0.25118	0.07639	0.32757
Winter Mid	0.23484	0.27798	0.23842	0.51641	0.22250	0.26565	0.23505	0.50070
Winter Off	0.20780	0.25095	0.10885	0.35980	0.20477	0.24792	0.11070	0.35862
Winter Super-Off	0.20724	0.25039	0.05810	0.30849	0.21462	0.25776	0.05373	0.31150
Baseline Credit				(0.08487)				(0.08487)
Tier 1 BSC		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15
Seasonal Average Rate								
Summer Average Rate	0.22330		0.12553	0.39198	0.22465		0.12713	0.39494
Winter Average Rate	0.21189		0.11194	0.36698	0.21096		0.11083	0.36494
Seasonal Delta	0.01142		0.01358	**0.02500**	0.01370		0.01630	**0.03000**
TOU Ratios								
Summer On	1.50801		5.37267		1.59781		5.36168	
Summer Mid	1.11146		2.93893		1.06908		3.00000	
Summer Off	1.00000		1.00000		1.00000		1.00000	
Winter Mid	1.13315		4.10390		1.03674		4.37429	
Winter Off	1.00270		1.87364		0.95413		2.06018	
Winter Super-Off	1.00000		1.00000		1.00000		1.00000	

Table 1-4
Illustrative Rates for TOU-D-PRIME

	TOU - PRIME							
	Current Rate With Basic Service Charge				Proposed Rate Year 4: October 2029			
	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total
Summer On	0.22097	0.25970	0.30842	0.56812	0.24701	0.29016	0.39346	0.68362
Summer Mid	0.22097	0.25970	0.10976	0.36946	0.24224	0.28539	0.08853	0.37392
Summer Off	0.13356	0.17229	0.07328	0.24557	0.14677	0.18991	0.06521	0.25513
Winter Mid	0.22626	0.26499	0.27853	0.54352	0.15449	0.19764	0.21496	0.41261
Winter Off	0.12544	0.16417	0.06193	0.22610	0.14985	0.19300	0.08047	0.27347
Winter Super-Off	0.12544	0.16417	0.06193	0.22610	0.15680	0.19995	0.03557	0.23552
Tier 1 BSC		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15
Seasonal Average Rate								
Summer Average Rate	0.16048		0.12732	0.32653	0.17720		0.13810	0.35845
Winter Average Rate	0.15214		0.11945	0.31033	0.15326		0.10204	0.29845
Seasonal Delta	0.00834		0.00786	**0.01621**	0.02394		0.03606	**0.06000**
TOU Ratios								
Summer On	1.65446		4.20879		1.68304		6.03359	
Summer Mid	1.65446		1.49782		1.65051		1.35761	
Summer Off	1.00000		1.00000		1.00000		1.00000	
Winter Mid	1.80373		4.49750		0.98526		6.04380	
Winter Off	1.00000		1.00000		0.95566		2.26255	
Winter Super-Off	1.00000		1.00000		1.00000		1.00000	

	Proposed Rate Glidepath TOU-PRIME															
	Year 1: October 2026				Year 2: October 2027				Year 3: October 2028				Year 4: October 2029			
	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total	Dist	Delivery Total	Gen	Total
Summer On	0.23415	0.27730	0.32283	0.60012	0.23841	0.28156	0.34692	0.62848	0.24270	0.28585	0.37044	0.65629	0.24701	0.29016	0.39346	0.68362
Summer Mid	0.23300	0.27615	0.10123	0.37738	0.23609	0.27924	0.09671	0.37595	0.23917	0.28232	0.09250	0.37482	0.24224	0.28539	0.08853	0.37392
Summer Off	0.14092	0.18406	0.06920	0.25327	0.14287	0.18602	0.06774	0.25376	0.14482	0.18797	0.06642	0.25439	0.14677	0.18991	0.06521	0.25513
Winter Mid	0.17213	0.21527	0.22685	0.44213	0.16645	0.20959	0.22324	0.43283	0.16057	0.20372	0.21925	0.42298	0.15449	0.19764	0.21496	0.41261
Winter Off	0.16015	0.20329	0.08492	0.28822	0.15679	0.19994	0.08357	0.28351	0.15337	0.19651	0.08208	0.27859	0.14985	0.19300	0.08047	0.27347
Winter Super-Off	0.14540	0.18855	0.04645	0.23500	0.14893	0.19207	0.04235	0.23443	0.15272	0.19587	0.03876	0.23462	0.15680	0.19995	0.03557	0.23552
Tier 1 BSC		6.00		6.00		6.00		6.00		6.00		6.00		6.00		6.00
Tier 2 BSC		12.08		12.08		12.08		12.08		12.08		12.08		12.08		12.08
Tier 3 BSC		24.15		24.15		24.15		24.15		24.15		24.15		24.15		24.15
Seasonal Average Rate																
Summer Average Rate	0.16953		0.12681	0.33949	0.17208		0.13058	0.34581	0.17464		0.13434	0.35213	0.17720		0.13810	0.35845
Winter Average Rate	0.15869		0.11049	0.31233	0.15688		0.10768	0.30771	0.15507		0.10486	0.30308	0.15326		0.10204	0.29845
Seasonal Delta	0.01083		0.01632	**0.02715**	0.01520		0.02290	**0.03810**	0.01957		0.02948	**0.04905**	0.02394		0.03606	**0.06000**
TOU Ratios																
Summer On	1.66161		4.66499		1.66875		5.12119		1.67589		5.57739		1.68304		6.03359	
Summer Mid	1.65347		1.46276		1.65249		1.42771		1.65150		1.39266		1.65051		1.35761	
Summer Off	1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000	
Winter Mid	1.18382		4.88407		1.11763		5.27065		1.05145		5.65722		0.98526		6.04380	
Winter Off	1.10142		1.82839		1.05283		1.97311		1.00425		2.11783		0.95566		2.26255	
Winter Super-Off	1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000		1.00000	

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

AGRICULTURAL AND PUMPING RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

Dated: **August 19, 2025**

Agricultural and Pumping Rate Group Rate Design Settlement Agreement

Table of Contents

Section	Page

Agricultural and Pumping Rate Group Rate Design Settlement Agreement

Table of Contents (Continued)

Section	Page

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

AGRICULTURAL AND PUMPING RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Agricultural and Pumping (A&P) Rate Group Rate Design Settlement Agreement (Agreement or Settlement Agreement) is entered into by and among Southern California Edison Company (SCE) and the California Farm Bureau Federation (CFBF) (collectively referred to hereinafter as Settling Parties).

1. PARTIES

A. SCE is an investor-owned public utility and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. CFBF is California's largest farm organization, working to protect family farms and ranches on behalf of its nearly 27,000 members statewide and as part of a nationwide network of more than 5.8 million members.

2. DEFINITIONS

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "Agricultural and Pumping Rate Group" refers to accounts, generally with demands equal to or less than 500 kW,[1] that are eligible for service on the following SCE rate schedules:

[1] Pursuant to D.18-01-012, the Applicability section of the TOU-PA-3 tariffs was revised to remove the 500 kW maximum demand threshold for any customer who meets SCE's Tariff Rule 1 definition of "Agricultural Power Service."

PA-1 and PA-2 (applicable to non-TOU A&P customers served on Catalina Island), TOU-PA-2 (applicable to A&P customers with monthly demands up to 199 kW), and TOU-PA-3 (applicable to A&P customers of demands of 200 kW to 500 kW, unless exempted from the 500 kW threshold in which case demands can exceed 500 kW).

B. "AP-I" or "Agricultural and Pumping – Interruptible" is a program that provides a year-round monthly credit to eligible A&P customers with a measured demand of 37 kW or greater, or with at least 50 horsepower of connected load, who allow SCE to temporarily interrupt electric service based on terms and conditions provided in the schedule.

C. "Base Rate" means the rate option (*i.e.,* Option D under this Agreement) in a rate class *(i.e.,* TOU-PA-2 or TOU-PA-3) against which all other options within the rate group are designed to be revenue-neutral.

D. "Commission" or "CPUC" means the California Public Utilities Commission.

E. "Critical Peak Pricing" or "CPP" means a demand response rate that provides a high, short-term, CPP energy charge of a predetermined level during 12 events of high load or other high-cost system conditions, as designated by SCE within the approved parameters. Typically, the time and duration of the CPP Energy Charge are predetermined, but the CPP event days are not predetermined. Participating customers receive a credit reflected in summer Demand Charges or Energy Charges, where applicable, on all days when CPP events are not called.

F. "Customer Charges" mean the fixed dollar-per-month charges applied to customers in the A&P Rate Group that are designed to recover the fixed customer costs of connection to SCE's system.

G. "Default Rate" means the rate option on which a customer is automatically placed when starting service unless the customer requests otherwise.

H. "Demand Charges" mean those charges that are comprised of Facilities-Related Demand (FRD) Charges and Time-Related Demand (TRD) Charges, which are based on a customer's maximum kilowatt (kW) in any time period (*i.e.*, FRD), or during a specified time-of-use (TOU) period (*i.e.*, TRD), within the billing period. Demand Charges recover a portion of SCE's delivery and generation costs, where such charges apply to a specific rate schedule.

I. “Design Demand Marginal Costs” (or “DDMC”), means the incremental cost associated with providing additional capacity on the distribution system.

J. “Distribution Grid” (or “Grid”) refers to the portion of DDMCs that are not Distribution Peak related.

K. “Distribution Peak” (or “Peak”) refers to the portion of DDMCs that are primarily sized to support the time-sensitive nature of coincident peak demand on the distribution system.

L. “Energy Charges” mean dollar-per-kilowatt-hour (kWh) charges that recover (1) the portion of SCE’s generation services revenues not recovered in TRD Charges; (2) the portion of SCE’s delivery services revenues that are not recovered in TRD Charges, FRD Charges or Customer Charges; and (3) other delivery services revenues for public purpose programs (including Energy Efficiency and CARE), New System Generation Service (NSGS), Nuclear Decommissioning, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and CPUC reimbursement fees. Energy Charges are designed to provide a price signal aligned with marginal cost differentials in TOU Energy Charges, where TOU Energy Charges apply to a particular rate schedule.

M. “EPMC” means equal percent of marginal cost. Because marginal cost revenues do not equal the utility’s revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group’s percentage share of marginal cost revenue responsibility by function (*i.e.,* separately for generation versus distribution, and customer).

N. “ERRA” means Energy Resource Recovery Account.

O. “Facilities-Related Demand Charges” or “FRD Charges” mean the charges applied to customers’ monthly peak demands that are not differentiated by TOU or by season, and that are designed to recover certain transmission and distribution costs that are defined to be unrelated to time of use.

P. “Functional SAPC Allocation” means allocation of SCE’s revenue requirement to each of SCE’s rate groups based on the system average percentage change (SAPC) for the particular function, *e.g.*, generation, or distribution and customer costs.

Q. "Legacy Option A" means legacy Schedule A rates. Legacy Option A rates are intended for eligible legacy accounts where the non-standby solar system is located behind the same meter as the load.

R. "Legacy Option B" means legacy Schedule B rates. Legacy Option B rates are intended for legacy standby accounts, legacy accounts that are virtually allocated credits under one of the virtual net energy metering (NEV-V or its NEM and NBT variants) or RES-BCT tariff options.

S. "MECs" means Marginal Energy Costs.

T. "PLRF" means "Peak Load Risk Factor," and represents the methodology used to assess capacity constraints on the distribution system and to assign peak-capacity-related design demand marginal costs to TOU periods.

U. "PTO" means permission to operate.

V. "Marginal Cost and Revenue Allocation Settlement Agreement" refers the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on June 30, 2025, concurrent with a motion to approve the settlement.

W. "RECC" or "Real Economic Carrying Charge" means a constant payment in real dollars that includes the recovery of capital investment, earnings, taxes and other capital carrying costs. The RECC, when escalated at the rate of inflation over the life of the asset, recovers the net present value of revenue requirement of a utility investment. It also represents the value of deferring a utility investment by a year.

X. "Standby service" means SCE's retail service to customers who supply a part or all of their electrical requirements from an onsite generating facility as defined, interconnected, and operated in accordance with SCE's Rule 21, Wholesale Distribution Access Tariff (WDAT) or Transmission Owners (TO) tariff, but who will require electric service from SCE's electrical system during periods of a partial or complete outage of the customer's generating facility.

Y. "Time-Related Demand Charges" or "TRD Charges" are generation or distribution marginal cost-based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities during the TOU periods.

Z. "TOU" means time-of-use. TOU periods are the time periods established for the provision of electric service in which TRD Charges or Energy Charges may vary in relation to the cost of service, and reflect the TOU periods adopted in D.18-07-006 (the final decision in SCE's 2018 Rate Design Window (RDW) proceeding).

3. <u>RECITALS</u>

A. In Phase 2 of SCE's 2025 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

B. On March 29, 2024, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application (A.) 24-03-019.

C. On August 26, 2024, SCE filed its Amended Application and served amended versions of its initial prepared testimony and supplemental testimony regarding changes to 2025 GRC Phase 2 residential rate designs to include a fixed charge structure as adopted in D.24-05-028.

D. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a June 3, 2024 prehearing conference.

E. The Public Advocates Office at the Commission served its initial testimony on November 22, 2024 but did not address A&P rate design issues. Intervenors, including CFBF, served their initial testimony on revenue allocation and/or A&P rate design issues on January 8, 2025.

F. SCE provided notice to all parties of its intent to conduct a settlement conference, and an initial settlement conference was held on January 3, 2025.

G. Continuing settlement discussions occurred among the Settling Parties after January 3, 2025.

H. On August 11, 2025, SCE provided notice to all parties pursuant to CPUC Rule of Practice and Procedure 12.1(b) of a settlement conference to review this Agreement.

I. In connection with settlement discussions among the Settling Parties, SCE used billing determinants from January 2023 – December 2023 for bill impact analyses provided in connection with this Agreement.

J. The Settling Parties have evaluated the impacts of the various proposals in this proceeding, desire to resolve all issues related to the design of SCE's A&P rates, and have reached agreement as indicated in Paragraph 4 of this Agreement.

K. Appendix A to this Agreement provides a comparison of the Settling Parties' positions related to A&P rate design issues that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and Appendix A, the terms of this Agreement shall control.

L. Appendix B provides illustrative A&P rates resulting from this Settlement Agreement. Consistent with Paragraph 11 of this Settlement Agreement, these class average summaries are for illustrative purposes only and have no precedential value. The rate summaries will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of the Revenue Allocation Settlement Agreement when rates are first implemented pursuant to the provisions of this Agreement.

4. AGREEMENT

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Settlement Agreement. Nothing in this Settlement Agreement shall be deemed to constitute an admission by any party that its position on any issue lacks merit or that its position has greater or lesser merit than the position taken by any other Settling Party. This Settlement Agreement is subject to the express limitation on precedent described in Paragraph 11. Unless specifically stated otherwise herein, this Agreement and its terms are intended to remain in effect from the date rate changes are implemented as a result of a Commission decision in this proceeding until a decision is implemented in of SCE's next GRC Phase 2.

A. Illustrative Rates

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the A&P Rate Group's share of the consolidated revenue requirement of $17,466 million described in more detail in Paragraph 4.B(1) of the Marginal Cost and Revenue Allocation (MCRA) Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the Revenue Allocation Settlement Agreement to reflect SCE's total system revenue requirement when this Agreement is implemented.

B. Common Rate Design Elements

Consistent with SCE's Application, rate structures for the A&P Rate Group will continue to generally consist of some combination of Customer Charges, TOU or seasonal Energy Charges, TRD Charges and FRD Charges. Consistent with the agreement reached in the Small Commercial settlement track, CPP will no longer be the default rate option for the TOU-PA-3 rate class upon implementation of this Agreement, and will remain available as an option for customers within the A&P Rate Group. Optional real-time pricing (RTP) rates also remain available for the A&P Rate Group. Finally, accounts eligible for legacy TOU period rate options in accordance with D.17-01-006 and D.17-10-018 (TOU OIR decisions), will remain on Legacy Option A and/or Legacy Option B until the end of their legacy period.[2]

1) Customer Charges

To mitigate bill impacts, Customer Charges for the TOU-PA-2 rate class shall be set at the TOU-PA-2 customer marginal cost, minus 50KVa transformation related costs, then EPMC scaled. The 50KVa transformation related costs are recovered via the FRD charge, with any imbalance recovered via a flat energy charge. The Customer Charge for TOU-PA-3 rate class shall be set at TOU-PA-3 customer marginal cost, minus 50kVa transformation related costs, then increased by 10%. The 50KVa transformation related costs are recovered via the FRD charge, with any imbalance recovered via a flat energy charge. Thereafter, these Customer Charges shall remain fixed during the attrition years of the 2025 GRC. The resulting monthly Customer Charges upon initial implementation of this Agreement are listed in the Table below:

Illustrative Monthly Customer Charges Table

Rate Class	Customer Charge
TOU-PA-2	$61.50
TOU-PA-3	$377.05

2) Energy Charges

The use of TOU Energy Charges to recover certain generation and distribution revenues is discussed in the Available Rate Options section below. To mitigate bill impacts certain TOU period rate differentials were "smoothed" or moderated as part of the

---

2 Legacy rate schedules will migrate off Legacy rates from October through December of 2027.

settled rate designs. When this Agreement is first implemented, these illustrative Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with Paragraph 4.B.6 of the MCRA Settlement Agreement. Thereafter, Energy Charges shall be adjusted consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement when SCE's authorized revenues change.

a) <u>Generation Revenues</u>

All generation energy revenues and a portion of generation capacity revenues are recovered via Energy Charges. The balance of generation capacity revenues are recovered via Demand Charges.

b) <u>Distribution Revenues</u>

TOU Energy Charges recover approximately 21% of the TOU-PA-2 distribution revenues, and 20% for TOU-PA-3. The balance of peak-capacity revenues and all grid-related revenues are recovered via Demand Charges.

c) <u>Other Revenues</u>

Energy Charges that are designed to recover revenues associated with transmission, public purpose programs, new system generation service, nuclear decommissioning, CARE balancing account, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and the CPUC reimbursement fee shall be established on the basis of the specified functional authorized revenue requirements and the terms specified in the MCRA Settlement Agreement.

3) <u>Demand Charges</u>

Demand charges consist of both TRD Charges and FRD Charges. TRD Charges are applied in the summer on-peak period and winter mid-peak periods for Option D and applied in the summer on-peak and mid-peak periods for legacy Option B. FRD Charges are not differentiated by season or TOU periods.

a) <u>TRD Charges</u>

The base rate (*i.e.*, Option D) for TOU-PA-2 and TOU-PA-3 will continue to collect certain generation capacity costs via TRD charges. However, to reflect the impact of ramp and the need for flexible capacity year-round, generation capacity TRD charges

shall apply both in the summer on-peak period (as they currently do) and also in the winter mid-peak period (as they currently do).[3] A summer on-peak Distribution TRD Charge shall apply, which reflects the recovery of approximately 50% of the EPMC scaled summer On-peak Distribution Design Demand revenues. A summer on-peak Generation TRD charge shall apply, and reflects 100 percent of the EPMC scaled summer On-peak generation capacity costs.
A winter mid-peak Generation TRD charge shall apply, which reflects approximately 70% of EPMC scaled winter mid-peak generation capacity revenues for TOU-PA-2 and approximately 64% for TOU-PA-3. To offer customers a menu of rate options, the "Option E" TOU-PA-2 and TOU-PA-3 rates do not include TRD charges. Illustrative TRD Charges are shown in the Table below.

Illustrative TRD Charges ($/kW) Table

Rate Class	Summer On-Peak (Generation)	Summer On-Peak (Distribution)	Winter Mid-Peak (Generation)	Winter Mid-Peak (Distribution)
TOU-PA-2	9.09	3.17	3.14	0
TOU-PA-3	10.34	3.4	3.22	0

When this Agreement is first implemented, these estimated TRD Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with Paragraph 4.B.6 of the MCRA Settlement Agreement. Thereafter, these estimated TRD Charges shall be adjusted consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement when SCE's authorized generation or distribution revenues change.

4) <u>FRD Charges</u>

Both Options D and E of TOU-PA-2 and TOU-PA-3 include an FRD Charge, which is designed to recover certain allocated delivery revenues, including SCE's adopted transmission revenues. For distribution-related revenues, the Option D FRD charge is designed to recover the 50kVa transformation related customer marginal costs not recovered via the Customer Charge, all Grid-related Distribution Design Demand marginal costs (DDMCs), and 50 percent of the mid-peaks, off-peaks, and super-off-peak Peak-Related Distribution

---

[3] TRD charges do not apply on weekends or holidays in the winter mid-peak period.

capacity costs. For Option E (for distribution), the FRD Charge recovers the 50kVa transformation-related customer marginal costs not recovered via the Customer Charge and Grid-related Distribution Design Demand marginal costs. Illustrative FRD Charges are shown in the Table below.[4]

Illustrative FRD Charges ($/kW) Table

Rate Class	Option D	Option E
TOU-PA-2	$13.83	$12.06
TOU-PA-3	$17.12	$15.17

When this Agreement is first implemented, the estimated FRD Charges shall be adjusted, as necessary, consistent with SCE's then-current authorized revenues and Paragraph 4.B.6 of the MCRA Settlement Agreement. The distribution component of the estimated FRD Charges shall be adjusted, as necessary, by the appropriate SAPC distribution scalar consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement when SCE's authorized revenues change. Similarly, the transmission component of the estimated FRD Charges shall be adjusted, as necessary, by the appropriate Federal Energy Regulatory Commission (FERC) formula rate adjustment when FERC-authorized transmission revenues change.

5) <u>Voltage Discounts</u>

A&P customers served at higher voltage delivery levels than the design voltage level for their rate class will receive a voltage discount reflecting their lower cost of service. SCE will establish the discount levels based on the difference in marginal costs of service between the design or predominant voltage level for a given rate class and the higher voltage service options. No modifications were proposed for the determination of the voltage discounts. Voltage discounts shall apply to the illustrative rate schedules, as indicated in Appendix B.

6) <u>Power Factor Adjustments</u>

No modifications were proposed for the determination of the power factor adjustment (PFA) rates, which are designed to recover the costs of additional capacitors installed

---

[4] FRD Charges for the optional 5-8pm D and E rates are reflected in Appendix B.

by SCE to improve power factor. PFA rates shall apply to the illustrative rate schedules, as indicated in Appendix B.

C. Available Rate Options

1) Schedule TOU-PA-2

SCE shall offer a menu of rate options to A&P customers within the TOU-PA-2 class, including the following:[5]

- Option D (base/default rate) using the standard TOU periods with a 4-9pm peak period;
- Option D-5to8 (optional rate) using a TOU period with a compressed 5-8pm peak period;
- Option E (optional rate) using the standard TOU periods with a 4-9pm peak period;
- Option E-5to8 (optional rate) using a TOU period with a compressed 5-8pm peak period;
- Option CPP (optional rate);
- Legacy Option A and Legacy Option B rates for eligible legacy solar customers.

a) TOU-PA-2: Option D

The proposed Option D rates reflect a settled rate design structure that incorporates the following key elements using a Customer Charge, TOU Energy Charges, TRD Charges and an FRD Charge:

- TOU periods as adopted in D.18-07-006;
- Customer Charges set at $61.50 per month, that will be fixed during the attrition years;

---

[5] Schedule TOU-PA-2 shall additionally continue to include a wind machine credit (*i.e.,* Special Condition 13 of Schedule TOU-PA-2). Customers are also eligible for the RTP rate.

- For distribution, TOU Energy Charges that recover approximately 21 percent of the distribution revenues, a summer on-peak TRD Charge that recovers approximately 50 percent of summer Peak-capacity revenues, and an FRD Charge that recovers 100 percent of Grid-related revenues.
- For generation, TOU Energy Charges recover generation energy costs and a portion of generation capacity revenues not recovered in the TRD Charge. Winter Mid-peak TRD is set at approximately 70% Peak-capacity revenues and Summer TRD is set to recover 100% Peak-capacity revenues.

b) <u>TOU-PA-2: Option E</u>

The proposed Option E rates reflect a settled rate design structure that incorporates the following key elements using a Customer Charge, TOU Energy Charges and an FRD Charge (no TRD Charges):

- TOU periods as adopted in D.18-07-006;
- Customer Charges set at $61.50 per month, that will be fixed during the attrition years;
- For distribution, TOU Energy Charges that recover all Peak-capacity revenues with smoothing and moderated TOU rate differentials to mitigate bill impacts as customers continue to transition to new TOU periods and experience time-differentiated distribution charges, and an FRD Charge that recovers all Grid-related revenues;
- For generation, recovery is via TOU Energy charges, with moderated[6] TOU differentials in the winter to mitigate bill impacts as customers continue to transition to the new TOU rates.

---

[6] Winter energy ratios set to 2018 GRC adopted ratios (1.47/1.17/1.0).

c) TOU-PA-2: Option CPP

The CPP rate option, which is an overlay on Option D, reflects the following:

- Will remain an optional rate for TOU-PA-2 customers;
- CPP event periods shall continue to be weekdays from 4-9 pm;
- The CPP event charge shall be set at $0.80 /kWh; and
- Bill protection will be offered to customers for up to one year.

d) TOU-PA-2: Option RTP

A&P customers will remain eligible for the RTP rate option, with the illustrative delivery rates reflected in Appendix B. No structural changes to the RTP rate option are proposed in this Agreement.

e) TOU-PA-2: Legacy Options A and B

A&P customers with behind-the-meter solar generation facilities who meet the requirements of D.17-01-006 and D.17-10-018 will continue to be eligible for Legacy Option A and/or Legacy Option B until the end of their legacy periods.[7] Eligible solar customers may be served on legacy rates for ten years from their individual PTO dates, but not to exceed July 31, 2027 (non-public agencies) or December 31, 2027 (public agencies), as established in D.17-01-006 and D.17-10-018. No structural changes to the Legacy Option A and Legacy Option B rate options are proposed in this Agreement.

2) Schedule TOU-PA-3

SCE shall offer a menu of rate options to A&P customers within the TOU-PA-3 class, including the following:

- Option D (base rate) using the standard TOU periods with a 4-9pm on peak period;
- Option D-5to8 (optional rate) using a TOU period with a compressed 5-8pm peak period;

[7] Legacy rate schedules will migrate off Legacy rates starting in October through December of 2027.

- Option E (optional rate) using the standard TOU periods with a 4-9pm on peak period;
- Option E-5to8 (optional rate) using a TOU period with a compressed 5-8pm peak period;
- Option CPP (Will no longer be the default rate);
- Legacy Option A and Legacy Option B rates for eligible legacy solar customers.

The descriptions of the settled rate structure associated with the rate options outlined above are consistent with those described above for TOU-PA-2, with the exception that the Customer Charges for TOU-PA-3 rate options shall initially be set at 10% above the SCE's proposed RECC customer marginal cost, minus the 50KVa transformation-related costs. The TOU differentials for winter generation energy rates are also different for the TOU-PA-3 rate options. For Option D, the winter generation energy differentials are set based on the 2025 GRC generation marginal cost ratios and for Option E, the differentials are set at the moderated ratios of 3.45/2.75/1.

a) <u>TOU-PA-3: Option D</u>

The proposed Option D rates reflect a settled rate design structure that incorporates the following key elements using a Customer Charge, TOU Energy Charges, TRD Charges and an FRD Charge:

- TOU periods as adopted in D.18-07-006;
- Customer Charges set at $377.05 per month, that will be fixed during the attrition years;
- For distribution, TOU Energy Charges that recover approximately 20 percent of the distribution revenues, a summer on-peak TRD Charge that recovers approximately 50 percent of summer Peak-capacity revenues, and an FRD Charge that recovers 100 percent of Grid-related revenues;

- For generation, TOU Energy Charges recover generation energy costs and a portion of generation capacity revenues not recovered in the TRD Charge. Winter Mid-peak TRD is set at approximately 64% Peak-capacity revenues and Summer TRD is set to recover 100% Peak-capacity revenues.

b) <u>TOU-PA-3: Option E</u>

The proposed Option E rates reflect a settled rate design structure that incorporates the following key elements using a Customer Charge, TOU Energy Charges and an FRD Charge (no TRD Charges):

- TOU periods as adopted in D.18-07-006;
- Customer Charges set at $377.05 per month, that will be fixed during the attrition years;
- For distribution, TOU Energy Charges that recover all Peak-capacity revenues with smoothing and moderated TOU rate differentials to mitigate bill impacts as customers continue to transition to new TOU periods and experience time-differentiated distribution charges, and an FRD Charge that recovers all Grid-related revenues;
- For generation, recovery is via TOU Energy charges, with moderated[8] TOU differentials in the winter to mitigate bill impacts as customers continue to transition to the new TOU rates.

c) <u>TOU-PA-3: Option CPP</u>

The CPP rate option, which is an overlay on Option D, reflects the following:

---

[8] Winter energy ratios set to 2018 GRC adopted ratios (3.45/2.75/1.0).

- The CPP rate option is no longer the default rate for TOU-PA-3 customers;
- CPP event periods shall continue to be weekdays from 4-9 pm;
- The CPP event charge shall be set at $0.80/kWh; and
- Bill protection will be offered to customers for up to one year.

d) <u>TOU-PA-3: Option RTP</u>

A&P customers will remain eligible for the RTP rate option, with the illustrative delivery rates reflected in Appendix B. No structural changes to the RTP rate option are proposed in this Agreement.

e) <u>TOU-PA-3: Legacy Options A and B</u>

A&P customers with behind-the-meter solar generation facilities who meet the requirements of D.17-01-006 and D.17-10-018 will continue to be eligible for Legacy Option A and/or Legacy Option B until the end of their legacy periods.[9] Eligible solar customers may be served on legacy rates for ten years from their individual PTO dates, but not to exceed July 31, 2027 (non-public agencies) or December 31, 2027 (public agencies), as established in D.17-01-006 and D.17-10-018. No structural changes to the Legacy Option A and Legacy Option B rate options are proposed in this Agreement.

3) <u>Schedule AP-I</u>

SCE shall continue to provide AP-I credits based on the customer's average summer on- and winter mid-peak demand. The level of credits shall reflect the incentive budget at the current level as shown in Appendix B.

D. <u>Time Management Load Control (TMLC) Device</u>

Settling Parties agree SCE will stop offering TMLC devices and disable active TMLC devices from their corresponding meter upon implementation of a final decision.

---

[9] Legacy rate schedules will migrate off Legacy rates starting in October through December of 2027.

E. Pump Testing Credit Program

Based on Parties' discussions, SCE conducted an analysis to study the load attributes of pump test customers. The study was then used to inform the development of a credit program with similarities to the current Wind Machine Credit offered to TOU-PA-2 customers. Key considerations in the design of the Pump Testing Credit included the mitigation of administrative burdens, simplicity to facilitate the efficient management of both energy and water usage by operators, and alignment of the program credit with periods of high solar production and low grid utilization.

The Settling Parties agree SCE will offer a credit program for Agricultural customers who perform pump testing and upgrades during the winter season defined as December 1st through February 28th. Eligibility for the credit program will be limited to TOU-PA-2 customers whose NAICS code begins with 1113 (Fruit and Tree Nut Farming) and operate below a load factor threshold of 2% in any given billing cycle within the December through February test period. Eligible testing hours will be limited to a two-hour window between 10:00 AM and Noon (PST). Qualifying customers will receive a credit applied to the applicable billing cycle, which will directly offset the demand charges stemming from peak demand that occur within the two-hour test window. Qualifying customers may perform pump tests for up to a total of eleven hours during the 10:00 AM to Noon testing period during each month of the winter season. In addition, qualifying customers who perform a pump test outside of the 10:00 AM to Noon test period will receive the test credit for the first such occurrence during the December through February test period. However, any additional occurrences of registered demands associated with a pump testing event that occur outside of the two-hour test window will continue to be assessed on a monthly or TOU basis as specified in the underlying rate schedule. Customers who need to test their pumps during the two-hour test window will be required to apply for the credit. SCE will communicate the availability of the pump test credit via its usual channels, similar to how it communicates about its wind machine credit offering.

SCE and CFBF commit to reviewing the program during the next GRC Phase 2 to discuss progress, additional eligibility, or adjustments to the program to ensure its success.

F. **Implementing Revenue Changes in Rates**

As described in the MCRA Settlement Agreement,[10] when SCE's authorized revenues change in the future, SCE will first adjust rate levels for the Base Rate schedules (without CPP elements), using a Functional SAPC adjustment. SCE will then rebalance optional rate levels to ensure revenue neutrality between the Base Rate schedule and the optional rate schedules within each individual rate class (*i.e.*, TOU-PA-2, TOU-PA-3). For example, generation revenue changes resulting from SCE's ERRA proceedings shall be allocated on a Functional SAPC basis, *i.e.*, the revised SCE generation revenue requirement would be allocated by applying a generation-level SAPC scalar based on the difference between present rate revenues and proposed rate revenues for the Base Rate schedules. The optional rate schedules will then be adjusted to ensure revenue neutrality on a functional basis within each individual rate class.

G. **Implementation of Settlement Agreement**

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1, 2026.

5. **INCORPORATION OF COMPLETE AGREEMENT**

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties. If the Commission does not approve this Agreement without modification, the terms and conditions reflected in this Agreement shall no longer apply to the Settling Parties.

6. **RECORD EVIDENCE**

The Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

---

[10] *See* Paragraph 4.B.7 of the Revenue Allocation Settlement Agreement.

7. SIGNATURE DATE

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

8. REGULATORY APPROVAL

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e*., Phase 2 of SCE's 2025 GRC. The Settling Parties shall use their best efforts to obtain prompt Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

9. COMPROMISE OF DISPUTED CLAIMS

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

10. NON-PRECEDENT

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Settlement Agreement is not precedential in any other pending or future proceeding before this Commission, unless the Commission expressly provides otherwise.

11. PREVIOUS COMMUNICATIONS

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to the resolution of A&P rate design issues. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

12. NON-WAIVER

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

13. EFFECT OF SUBJECT HEADINGS

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

14. GOVERNING LAW

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

15. NUMBER OF ORIGINALS

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: August 19, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Michael Backstrom

By: Michael Backstrom
Title: Vice President, Regulatory Affairs

Dated: August 19, 2025

CALIFORNIA FARM BUREAU FEDERATION

/s/ Kevin Johnston

By: Kevin Johnston
Title: Director and Counsel

Appendix A

Comparison of Parties' Positions on Agricultural and Pumping Rate Design Issues

Comparison of Parties' Positions
Agricultural & Pumping Rate Groups

Issue	SCE	CFBF	2025 GRC Settled Position
TOU-PA-2, Option D (Base Rate) Rate Design	• Continue to offer Option D • Customer Charge: ~$33/mo, adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered via a combination of TOU Energy Charges and TRD Charges • Distribution Peak: recovered via a combination of TOU cent-per-kWh Energy Charges, TRD Charge and FRD Charge • Distribution Grid: recovered via an FRD Charge	• Recommends that the parties work together to examine the need for, and the potential forms of, various mechanisms that could help mitigate potentially large rate increases to some customer classes	• Offer a modified Option D based on settled rate design that incorporates: o Customer charges to be set at $61.50 during implementation and shall remain fixed during the attrition years. o For distribution, TOU Energy Charges recover 50% of Peak capacity costs w/ smoothing and moderated TOU rate differentials to mitigate bill impacts, summer on-peak TRD Charge recovers 50% summer Peak-capacity cost, and FRD Charge recovers Grid-related costs and 50% of remaining Peak-related costs of the mid-peak, off-peak and SOP periods. o For generation, TOU Energy Charges recover generation energy costs and a portion of generation capacity costs not recovered in the TRD Charge, with moderated TOU differentials in the winter to mitigate bill impacts as customers transition to the new TOU rates. The winter mid-peak TRD charges shall initially be set to recover approximately 70% of generation capacity costs.
TOU-PA-2, Option E (Optional Rate) Rate Design	• Continue to offer Option E (maintain no TRD structure) • Customer Charge: ~$33/mo, adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered entirely via TOU cent-per-kWh Energy Charges • Distribution Peak: recovered entirely via cent-per-kWh Energy Charge • Distribution Grid: recovered via an FRD Charge	• Same as TOU-PA-2-D	• Offer a modified Option E based on settled rate design that incorporates: o Customer charges to be set at $61.50 during implementation and shall remain fixed during the attrition years. o For distribution, TOU Energy Charges recover all Peak-capacity costs with smoothing and TOU rate differential moderation to mitigate bill impacts, an FRD Charge recovers all Grid-related costs, and no distribution TRD o For generation, use SCE's proposal with moderated TOU rate differentials for winter energy rates to mitigate bill impacts
TOU-PA-3, Option D (Base Rate) Rate Design	• Continue to offer Option D • Customer Charge: ~$573/mo, adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge	• Recommends that the parties work together to examine the need for, and the potential forms of, various mechanisms that could help mitigate	Same as TOU-PA-2, Option D, with the exception that Customer Charges will be set at 10% above the RECC customer marginal cost, minus the 50KVa transformation related costs. The 50KVa transformation costs are included in

Issue	SCE	CFBF	2025 GRC Settled Position
	• Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered via a combination of TOU Energy Charges and TRD Charges • Distribution Peak: recovered via a combination of TOU cent-per-kWh Energy Charges, TRD Charge and FRD Charge • Distribution Grid: recovered via an FRD Charge	potentially large rate increases to some customer classes • Recommends that SCE limit the increase to the TOU-PA-3 monthly customer charge to no more than 5%, with the resulting class revenue shortfall to be re-allocated to the energy-based rates	the FRD Charge, with the recovery of any remaining customer marginal cost revenue deficiencies included as a flat distribution energy charge. The resulting customer charge is $377.05 and shall remain fixed during the attrition years.
TOU-PA-3, Option E (Optional Rate) Rate Design	• Propose to offer Option E as the replacement for Option A (maintain no TRD structure) • Customer Charge: ~$573/mo., adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered entirely via TOU cent-per-kWh Energy Charges • Distribution Peak: recovered entirely via cent-per-kWh Energy Charge • Distribution Grid: recovered via an FRD Charge	• Same as TOU-PA-3 Option D above	Same as TOU-PA-2, Option E, with the exception that Customer Charges will be set at 10% above the RECC customer marginal cost, minus the 50KVa transformation related costs. The 50KVa transformation costs are included in the FRD Charge, with the recovery of any remaining customer marginal cost revenue deficiencies included as a flat distribution energy charge. The resulting customer charge is $377.05 and shall remain fixed during the attrition years.
Solar Legacy Rates (Legacy Options A and B)	Maintain same eligibility, duration, rate options, and rate structures from the 2018 GRC.		Maintain same eligibility, duration, rate options, and rate structures from the 2018 GRC.
Critical Peak Pricing (CPP)	• Option CPP shall no longer be the default rate option for TOU-PA-3 • CPP event periods will coincide with the updated peak periods (*i.e.*, weekdays from 4-9 p.m.) • CPP Event Charge will remain $0.80/kWh • Bill protection will be offered to customers for up to one year		• Maintain current CPP rate structures and outreach and customer care efforts. • Allow TOU-PA-3 customers to opt-in versus default to CPP
Schedule AP-I	• Align AP-I with the underlying base rate attributes adopted in this proceeding		• SCE shall continue to provide AP-I credits based on the customer's average summer on- and winter mid-peak demand.
Time Management Load Control (TMLC) Device	• Implement discontinuation of its support of TMLC devices and disable active TMLC devices from their corresponding meter upon implementation of changes stemming from the 2025 GRC Ph 2 decision.	• Agrees to timeline	• Settling Parties agree to continue with discontinuation of TMLC devices for existing customers upon implementation of a decision in this proceeding.
Pump Testing Credit		• Proposed a credit against for increased demand charges associated with pump testing events that occur between November 1 – February 1.	• Settling Parties agree to implement a Pumping Test Credit for qualifying TOU-PA-2 customers during the period December 1 – February 28 pursuant to the terms outlined in Section 4.E.

Issue	SCE	CFBF	2025 GRC Settled Position
		• The credit would be available to agricultural customers taking service under any agricultural rate schedule, with a one-hour service window, and up to a certain kW of registered demand. • The credit would be available for required testing under the Sustainable Groundwater Management Act year-round. • CFBF stated that it is open to advance notice or compliance requirements that SCE deems necessary provided they are not overly burdensome.	

Appendix B

Illustrative Agricultural and Pumping Rate Group Rates

Table 1
Illustrative Rates for TOU-PA-2-D 4-9PM

	October 2024 TOU-PA-2 Option D (4-9PM)					Proposed TOU-PA-2-D (4-9PM)				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Bill-months		$94.98			$94.98		$61.50			$61.50
On-MWh	(0.00005)	0.04908	0.11517	0.03629	$0.20049	(0.00005)	0.07849	0.13929	0.03520	$0.25292
Mid-MWh	(0.00005)	0.04908	0.10501	0.03629	$0.19033	(0.00005)	0.05218	0.10244	0.03520	$0.18978
Off-MWh	(0.00005)	0.01459	0.06949	0.03629	$0.12032	(0.00005)	0.02331	0.07624	0.03520	$0.13470
SOff-MWh										
On-MW		4.53	11.66		$16.19		3.17	9.09		$12.27
Mid-MW										$0.00
Off-MW										$0.00
SOff-MW										
Max-MW	2.00	14.32			$16.32	2.00	13.83			$15.83
Max-MVar										
Winter										
Bill-months		$94.98					$61.50			
On-MWh										
Mid-MWh	(0.00005)	0.04908	0.09019	0.03629	$0.17551	(0.00005)	0.01141	0.09840	0.03520	$0.14496
Off-MWh	(0.00005)	0.01459	0.07177	0.03629	$0.12260	(0.00005)	0.00893	0.07831	0.03520	$0.12238
SOff-MWh	(0.00005)	0.00599	0.06130	0.03629	$0.10353	(0.00005)	0.01310	0.06687	0.03520	$0.11512
On-MW										
Mid-MW		0.00	2.64		$2.64		0.00	3.14		$3.14
Off-MW										
SOff-MW										
Max-MW	2.00	14.32			$16.32	2.00	13.83			$15.83

Table2
Illustrative Rates for TOU-PA-2-D 5-8PM

	October 2024 TOU-PA-2 Option D (5-8PM)					Proposed TOU-PA-2-D (5-8PM)				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Bill-months		$94.98			$94.98		$61.50			$61.50
On-MWh	(0.00005)	0.05313	0.22941	0.03629	$0.31878	(0.00005)	0.08877	0.19944	0.03520	$0.32336
Mid-MWh	(0.00005)	0.05313	0.21639	0.03629	$0.30576	(0.00005)	0.04815	0.16710	0.03520	$0.25040
Off-MWh	(0.00005)	0.01636	0.06513	0.03629	$0.11773	(0.00005)	0.02992	0.07770	0.03520	$0.14276
SOff-MWh										
On-MW		3.06	11.16		$14.22		2.32	7.89		$10.20
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	2.00	15.03			$17.03	2.00	13.83			$15.83
Max-MVar										
Winter										
Bill-months		$94.98					$61.50			
On-MWh										
Mid-MWh	(0.00005)	0.05313	0.09348	0.03629	$0.18285	(0.00005)	0.01226	0.09970	0.03520	$0.14711
Off-MWh	(0.00005)	0.01636	0.07439	0.03629	$0.12699	(0.00005)	0.00855	0.07934	0.03520	$0.12304
SOff-MWh	(0.00005)	0.00699	0.06352	0.03629	$0.10675	(0.00005)	0.01336	0.06775	0.03520	$0.11626
On-MW										
Mid-MW		0.00	2.23		$2.23		0.00	3.78		$3.78
Off-MW										
SOff-MW										
Max-MW	2.00	15.03			$17.03	2.00	13.83			$15.83

Table 3
Illustrative Rates for TOU-PA-2-E 4-9PM

	October 2024 TOU-PA-2 Option E (4-9PM)					Proposed TOU-PA-2-E (4-9PM)				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Bill-months		$94.98			$94.98		$61.50			$61.50
On-MWh	(0.00005)	0.09294	0.38753	0.03629	$0.51671	(0.00005)	0.11505	0.18102	0.03520	$0.33122
Mid-MWh	(0.00005)	0.09294	0.10501	0.03629	$0.23419	(0.00005)	0.07649	0.13313	0.03520	$0.24478
Off-MWh	(0.00005)	0.02763	0.06949	0.03629	$0.13336	(0.00005)	0.03417	0.09907	0.03520	$0.16839
SOff-MWh										
On-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Mid-MW										$0.00
Off-MW										$0.00
SOff-MW										
Max-MW	2.00	12.10			$14.10	2.00	12.06			$14.06
Max-MVar										
Winter										
Bill-months		$0.00					$61.50			
On-MWh										
Mid-MWh	(0.00005)	0.04327	0.10444	0.03629	$0.18395	(0.00005)	0.02091	0.11415	0.03520	$0.17020
Off-MWh	(0.00005)	0.03443	0.08311	0.03629	$0.15378	(0.00005)	0.01635	0.09083	0.03520	$0.14234
SOff-MWh	(0.00005)	0.02940	0.07097	0.03629	$0.13661	(0.00005)	0.02400	0.07757	0.03520	$0.13671
On-MW										
Mid-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Off-MW										
SOff-MW										
Max-MW	2.00	12.10			$14.10	2.00	12.06			$14.06

Table 4
Illustrative Rates for TOU-PA-2-E 5-8PM

	October 2024 TOU-PA-2 Option E (5-8PM)					Proposed TOU-PA-2-E (5-8PM)				
	Trans	**Distrb**	**Gen**	**Other**	**Total**	**Trans**	**Distrb**	**Gen**	**Other**	**Total**
Summer										
Bill-months		$94.98			$94.98		$61.50			$61.50
On-MWh	(0.00005)	0.10626	0.64502	0.03629	$0.78752	(0.00005)	0.11964	0.24618	0.03520	$0.40096
Mid-MWh	(0.00005)	0.10626	0.21639	0.03629	$0.35889	(0.00005)	0.06489	0.20625	0.03520	$0.30630
Off-MWh	(0.00005)	0.03271	0.06513	0.03629	$0.13408	(0.00005)	0.04032	0.09590	0.03520	$0.17137
SOff-MWh										
On-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Mid-MW										$0.00
Off-MW										$0.00
SOff-MW										
Max-MW	2.00	12.10			$14.10	2.00	12.06			$14.06
Max-MVar										
Winter										
Bill-months		$94.98					$61.50			
On-MWh										
Mid-MWh	(0.00005)	0.04342	0.10489	0.03629	$0.18455	(0.00005)	0.02247	0.11787	0.03520	$0.17549
Off-MWh	(0.00005)	0.03456	0.08346	0.03629	$0.15426	(0.00005)	0.01568	0.09380	0.03520	$0.14462
SOff-MWh	(0.00005)	0.02951	0.07127	0.03629	$0.13702	(0.00005)	0.02449	0.08010	0.03520	$0.13973
On-MW										
Mid-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Off-MW										
SOff-MW										
Max-MW	2.00	12.10			$14.10	2.00	12.06			$14.06

Table 5
Illustrative Rates for TOU-PA-3-D 4-9PM

	October 2024 TOU-PA-3 Option D (4-9PM)					Proposed TOU-PA-3-D (4-9PM)				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Bill-months		$563.95			$563.95		$377.05			$377.05
On-MWh	(0.00005)	0.04059	0.10006	0.03511	$0.17571	(0.00005)	0.06624	0.11146	0.03391	$0.21156
Mid-MWh	(0.00005)	0.04059	0.09128	0.03511	$0.16693	(0.00005)	0.04889	0.08205	0.03391	$0.16481
Off-MWh	(0.00005)	0.01274	0.06048	0.03511	$0.10828	(0.00005)	0.01967	0.06110	0.03391	$0.11463
SOff-MWh										
On-MW		5.28	12.45		$17.73		3.40	10.34		$13.73
Mid-MW										
Off-MW										
Max-MW	2.74	14.63			$17.37	2.74	17.12			$19.86
Max-MVar										
Winter										
Bill-months		$563.95					$377.05			
Mid-MWh	(0.00005)	0.04059	0.07739	0.03511	$0.15304	(0.00005)	0.00967	0.07698	0.03391	$0.12051
Off-MWh	(0.00005)	0.01274	0.07789	0.03511	$0.12569	(0.00005)	0.00768	0.08008	0.03391	$0.12161
SOff-MWh	(0.00005)	0.00582	0.04096	0.03511	$0.08184	(0.00005)	0.01097	0.03553	0.03391	$0.08035
On-MW										
Mid-MW		0.00	2.68		$2.68		0.00	3.22		$3.22
Off-MW										
SOff-MW										
Max-MW	2.74	14.63			$17.37	2.74	17.12			$19.86

Table 6
Illustrative Rates for TOU-PA-3-D 5-8PM

	October 2024 TOU-PA-3 Option D (5-8PM)					Proposed TOU-PA-3-D (5-8PM)				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Bill-months		$563.95			$563.95		$377.05			$377.05
On-MWh	(0.00005)	0.04567	0.19505	0.03511	$0.27578	(0.00005)	0.07806	0.17543	0.03391	$0.28735
Mid-MWh	(0.00005)	0.04567	0.18398	0.03511	$0.26471	(0.00005)	0.03908	0.14822	0.03391	$0.22116
Off-MWh	(0.00005)	0.01432	0.05689	0.03511	$0.10627	(0.00005)	0.02392	0.05981	0.03391	$0.11760
SOff-MWh										
On-MW		3.91	11.93		$15.84		2.55	9.68		$12.23
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	2.74	15.30			$18.04	2.74	17.52			$20.26
Max-MVar										
Winter										
Bill-months		$563.95					$377.05			
On-MWh										
Mid-MWh	(0.00005)	0.04567	0.07775	0.03511	$0.15848	(0.00005)	0.01003	0.08101	0.03391	$0.12490
Off-MWh	(0.00005)	0.01432	0.07824	0.03511	$0.12762	(0.00005)	0.00763	0.07881	0.03391	$0.12029
SOff-MWh	(0.00005)	0.00588	0.04107	0.03511	$0.08201	(0.00005)	0.01099	0.03584	0.03391	$0.08069
On-MW										
Mid-MW		0.00	2.98		$2.98		0.00	4.03		$4.03
Off-MW										
SOff-MW										
Max-MW	2.74	15.30			$18.04	2.74	17.12			$19.86

Table7
Illustrative Rates for TOU-PA-3-E 4-9PM

	October 2024 TOU-PA-3 Option E (4-9PM)					Proposed TOU-PA-3-E 4-9PM				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Bill-months		$563.95			$563.95		$377.05			$377.05
On-MWh	(0.00005)	0.07778	0.33175	0.03511	$0.44459	(0.00005)	0.09863	0.15140	0.03391	$0.28389
Mid-MWh	(0.00005)	0.07778	0.09128	0.03511	$0.20412	(0.00005)	0.07280	0.11137	0.03391	$0.21803
Off-MWh	(0.00005)	0.02441	0.06048	0.03511	$0.11995	(0.00005)	0.02929	0.08285	0.03391	$0.14600
SOff-MWh										
On-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	2.74	11.79			$14.53	2.74	15.17			$17.91
Max-MVar										
Winter										
Bill-months		$563.95					$377.05			
On-MWh										
Mid-MWh	(0.00005)	0.04598	0.11051	0.03511	$0.19155	(0.00005)	0.02111	0.11057	0.03391	$0.16555
Off-MWh	(0.00005)	0.03663	0.08803	0.03511	$0.15972	(0.00005)	0.01680	0.08808	0.03391	$0.13874
SOff-MWh	(0.00005)	0.01333	0.03204	0.03511	$0.08043	(0.00005)	0.01201	0.03206	0.03391	$0.07793
On-MW										
Mid-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Off-MW										
SOff-MW										
Max-MW	2.74	11.79			$14.53	2.74	15.17			$17.91

Table 8
Illustrative Rates for TOU-PA-3-E 5-8PM

	October 2024 TOU-PA-3 Option E (5-8PM)					Proposed TOU-PA-3-E 5-8PM				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Bill-months		$563.95			$563.95		$377.05			$377.05
On-MWh	(0.00005)	0.09135	0.54416	0.03511	$0.67057	(0.00005)	0.11140	0.22846	0.03391	$0.37372
Mid-MWh	(0.00005)	0.09135	0.18398	0.03511	$0.31039	(0.00005)	0.05578	0.19302	0.03391	$0.28266
Off-MWh	(0.00005)	0.02865	0.05689	0.03511	$0.12060	(0.00005)	0.03414	0.07789	0.03391	$0.14590
SOff-MWh										
On-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	2.74	11.79			$14.53	2.74	15.17			$17.91
Max-MVar										
Winter										
Bill-months		$563.95					$377.05			
On-MWh										
Mid-MWh	(0.00005)	0.04727	0.11561	0.03511	$0.19794	(0.00005)	0.02222	0.11715	0.03391	$0.17322
Off-MWh	(0.00005)	0.03765	0.09209	0.03511	$0.16480	(0.00005)	0.01743	0.09332	0.03391	$0.14461
SOff-MWh	(0.00005)	0.01371	0.03352	0.03511	$0.08229	(0.00005)	0.01227	0.03397	0.03391	$0.08010
On-MW										
Mid-MW		0.00	0.00		$0.00		0.00	0.00		$0.00
Off-MW										
SOff-MW										
Max-MW	2.74	11.79			$14.53	2.74	15.17			$17.91

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

<u>LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT</u>

Dated: **August 25, 2025**

Large Power Rate Group Rate Design Settlement Agreement

Table of Contents

Section **Page**

Large Power Rate Group Rate Design Settlement Agreement

Table of Contents

Section **Page**

Large Power Rate Group Rate Design Settlement Agreement

Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Large Power Rate Group Rate Design Settlement Agreement (Agreement or Settlement Agreement) is entered into by and among the undersigned Parties hereto, with reference to the following:

1. PARTIES

The Parties to this Agreement are Southern California Edison Company (SCE); California Large Energy Consumers Association (CLECA); Electrify America, LLC; Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); the Energy Producers and Users Coalition (EPUC); California Manufacturers & Technology Association (CMTA); and, Walmart Inc (referred to hereinafter collectively as Settling Parties or individually as a Party).

A. SCE is an investor-owned public utility (IOU) and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. CLECA is an organization of large, high voltage, high load factor industrial electric bundled service, CCA and DA customers located throughout the state. These companies are in the steel, cement, industrial and medical gas, beverage, minerals processing, cold storage, and pipeline transportation industries, and share the fact that electricity costs comprise a significant portion of their cost of production.

C. Electrify America, LLC is an electric vehicle charging network with more than 4,400 fast chargers at more than 1,000 locations across the United States.

D. EUF is an *ad hoc* group that represents the interests of medium and large bundled service and DA customers in California, with locations in IOU and/or municipal utility service areas, taking service on rate schedules primarily for accounts with demand above 100 kilowatts (kW).

E. CMTA is a trade association representing the interests of 25,000 large and small manufacturers in California and 1.2 million employees. Many of its members receive electrical service from SCE as either bundled service or DA customers.

F. SEIA is the national trade association of the solar and storage industry. Through outreach and education, SEIA and its over 1200 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy and storage.

G. EPUC represents the end-use and customer generation interests of the following companies: California Resources Corporation, Chevron U.S.A. Inc., PBF Holding Company, Phillips 66 Company, and Tesoro Refining and Marketing Company LLC.

H. Walmart Inc. is a multinational retail corporation that operates 303 retail units, 17 distribution centers, and four fulfillment centers and employs over 104,000 associates in California.

2. <u>DEFINITIONS</u>

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "AC" means "alternating current."

B. "Added Facilities" are customer-dedicated, SCE-maintained electrical distribution facilities as defined in SCE's Electric Rule 2 tariff.

C. “AL” means an Advice Filing, sometimes referred to as an Advice Letter filing, at the CPUC.

D. “APS” means Automatic Powershift.

E. “Backup Service” is the electric service that is provided by SCE to a customer who has an on-site generating facility during unscheduled outages of the customer’s on-site generator.

F. “Base Interruptible Program” or “BIP” means the rate schedule applicable to customers with demands of 200 kW or more who receive a credit applied to their summer and winter season Time Related Demand (TRD) Charges in return for the customer’s agreement to reduce its demand to a specified level within either 15 or 30 minutes of notification by SCE of the need to reduce load.

G. “Base Rate” means the rate option (*e.g.*, TOU-GS-3, Option D) in a rate class (*e.g.*, TOU-GS-3) against which all other options within the rate group are designed to be revenue-neutral.

H. “BTM” means “behind-the-meter.”

I. “CAISO” means the California Independent System Operator.

J. “CA” means “Community Aggregation.”

K. “Capacity Reservation Charge” or “CRC” means the charge assessed to Standby customers based on the customer’s designated kW level of Standby Demand.

L. “CCA” means Community Choice Aggregation.

M. “C&I” means Commercial and Industrial customers.

N. “Cold Ironing” means the provision of electrical power for lights, heating, machinery or other needs of an ocean-going vessel at the Port of Long Beach or Port of Hueneme as replacement for the vessel’s auxiliary internal combustion engines or to a truck at truck stops where the truck’s internal combustion engine is turned off. For purposes of eligibility, the electric usage for Cold Ironing must be separately metered and at least 90 percent of the metered load must displace power generation associated with vessels or trucks that would otherwise be provided by internal combustion generation on the vessel or the truck (or as additionally designated in SCE's tariffs).

O. "Commission" or "CPUC" means the California Public Utilities Commission.

P. "Customer Charges" mean the fixed dollar-per-month charges applied to customers in the C&I rate classes that are designed to recover the fixed customer costs of connection to SCE's system.[1]

Q. "DA" means Direct Access.

R. "Default Rate" means the rate schedule on which the customer is automatically placed when starting service unless the customer requests otherwise.

S. "Demand Charges" mean those charges that are comprised of Facilities Related Demand (FRD) Charges and Time-Related Demand (TRD) Charges, which are based on the customer's maximum kW in any time period (*i.e.*, FRD), or during a specified time-of-use (TOU) period (*i.e.*, TRD), within a billing period. Demand Charges recover a portion of SCE's distribution and generation costs, where such charges apply to a specific rate schedule.

T. "DDMC" or "Design Demand Marginal Costs" means the incremental cost associated with providing additional capacity on the distribution system.

U. "DER" means "Distributed Energy Resource."

V. "Distribution Grid" (or "Grid") refers to the portion of DDMCs that are not Distribution Peak-related.

W. "Distribution Peak" (or "Peak") refers to the portion of DDMCs that are primarily sized to support the time-sensitive nature of coincident peak demand on the distribution system.

X. "Energy Charges" mean the dollar-per-kilowatt-hour (kWh) charges that recover (1) the portion of SCE's generation services revenues not recovered in TRD Charges; (2) the portion of SCE's delivery services revenues that are not recovered in TRD, FRD or Customer Charges; and (3) other delivery services revenues for public purpose programs

[1] The term "customer" as used in this Agreement generally refers to a service account when used in the context of eligibility and the rates for a particular tariff or rate schedule.

(including Energy Efficiency and California Alternate Rates For Energy (CARE), New System Generation Service (NSGS), Nuclear Decommissioning, CARE Balancing Account, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge,[2] demand response programs, and CPUC reimbursement fees). TOU differentiated Energy Charges are designed to provide a price signal consistent with marginal cost differentials in TOU Energy Charges, where TOU Energy Charges apply to a specific schedule.

Y. "EPMC" means equal percent of marginal cost. Because marginal cost revenues do not equal the utility's revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group's percentage share of marginal cost revenue responsibility by function (*i.e.*, separately for generation costs, and combined distribution and customer costs).

Z. "EV" means "electric vehicle."

AA. "Facilities Related Demand Charges" or "FRD Charges" mean the charges applied to customers' monthly peak demands that are not differentiated by TOU or by season, and that are designed to recover certain transmission and distribution costs that are defined to be unrelated to time of use.

BB. "FLT" means "final line transformer."

CC. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change (SAPC) for the particular function, *e.g.*, generation, or distribution and customer costs.

DD. "GCMC" means "generation capacity marginal costs."

EE. "Generation Peak" refers to the portion of GCMCs that are incurred to support the electric system during maximum system demand.

FF. "Large Power Rate Group" means the following SCE rate classes: (1) the TOU-GS-3 rate class, which is comprised of C&I customers with demands between 200 kW and 500 kW;

---

[2] Fixed Recovery Charge refers to fixed recovery charges defined in Public Utilities Code Section 850(b)(7) and authorized by the Commission pursuant to Public Utilities Code Section 850(a)(2).

(2) the TOU-8 rate classes, comprised of customers with demands that are more than 500 kW and are differentiated by service voltage as follows: TOU-8-Subtransmission (TOU-8-Sub), which is for service above 50 kV; TOU-8-Primary (TOU-8-Pri), which is for service from 2 kV to 50 kV; and TOU-8-Secondary (TOU-8-Sec), which is for service below 2 kV; and (3) the three TOU-8-Standby (TOU-8-S) rate classes, with service voltage differentiation being the same as the three TOU-8 rate classes.

GG. "OAT" means the customer's otherwise applicable tariff.

HH. "Paired storage" means BTM electric storage technology including, but not limited to, electric battery systems, that are combined behind the same meter or billed on the same service account as other DERs, usually solar.

II. "PLS" or "Permanent Load Shift" means technologies that are installed to allow customers to shift load that would otherwise occur during peak periods to off-peak periods on a permanent basis.

JJ. "PLRF" means "Peak Load Risk Factor," and represents the methodology used to assess capacity constraints on the distribution system and to assign peak-capacity-related design demand marginal costs to TOU periods.

KK. "MCRA Settlement Agreement" means the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on June 30, 2025.

LL. "RDW" means Rate Design Window proceeding.

MM. "Renewable Distributed Generation Technologies" means renewable generation technology as defined in the Statewide California Solar Initiative (CSI), the Self-Generation Incentive Program (SGIP), or their successors.

NN. "RECC" or "Real Economic Carrying Charge," means a constant payment in real dollars that includes the recovery of the capital investment, earnings, taxes, and other capital carrying costs. The RECC when escalated at the rate of inflation over the life of the asset recovers the net present value of revenue requirement of a utility investment. It also represents the value of deferring a utility investment by a year.

OO. "RTP" means Real Time Pricing.

PP. "Standby Algorithm," or "Algorithm" is the algorithm adopted by the CPUC in Decision (D.)16-03-030, approving SCE's 2015 GRC Phase 2.

QQ. "Standby Demand Backup Charge" are TRD Charges based on the lesser of the Standby Demand or the maximum Backup Demand for the relevant TRD period calculated for each 15-minute interval as the difference between the 15-minute interval maximum SCE metered demand (kW) and the 15-minute interval Intermediate Supplemental Demand, but not less than zero.

RR. "Standalone storage" means BTM electric storage technology including, but not limited to, electric battery systems that are not combined behind the same meter or billed on the same service account as other DERs.

SS. "SCC" or Supplemental Contract Capacity is the level of kW regularly served by SCE for Standby customers.

TT. "Time-Related Demand Charges" or "TRD Charges" are generation or distribution marginal-cost-based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities during the TOU periods.

UU. "TOU" means time-of-use. TOU periods are the time periods established for the provision of electric service in which Demand Charges or Energy Charges may vary in relation to the cost of service, and reflect the TOU periods adopted in D. 17-08-006.

VV. "ZEV" means Zero-Emissions Vehicle.

3. <u>RECITALS</u>

A. In Phase 2 of SCE's 2025 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

B. On March 29, 2024, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application (A.) 24-03-019.

C. On August 26, 2024, SCE filed its Amended Application and served amended versions of its initial prepared testimony and supplemental testimony regarding changes to 2025 GRC Phase 2 residential rate designs to include a fixed charge structure as adopted in D.24-05-028.

D. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a June 3, 2024 prehearing conference.

E. The Public Advocates Office served its initial testimony on November 22, 2024, then served amended testimony on December 27, 2024.

F. Intervenors, including the Settling Parties to this Agreement, served their initial prepared testimony on January 8, 2025.

G. The following intervenors submitted prepared testimony regarding Medium and Large Power Rate Design Issues: CLECA, and SEIA.

H. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on January 16, 2025.

I. Continuing settlement discussions occurred among the parties after January 16, 2025. Specific to this Settlement Agreement, the Settling Parties commenced settlement discussions on March 10, 2025.

J. Appendix A to this Agreement provides a comparison of the Settling Parties' positions, where applicable, related to Medium and Large Power Rate Group rate design issues that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and Appendix A, the terms of this Agreement shall control. Appendix B provides illustrative Medium and Large Power Rate Group rates resulting from this Settlement Agreement. Consistent with Paragraph 11 of this Settlement Agreement, these class average summaries are for illustrative purposes only. The rate summaries will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of the MCRA Settlement Agreement when rates are first implemented pursuant to the provisions of this Agreement.

K. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to rate design regarding Medium and Large Power Rate Group customers as set forth in this Agreement beginning with the implementation of a CPUC decision approving this Agreement, and, in consideration of the mutual obligations, covenants and conditions contained herein, have reached agreement as indicated in Paragraphs 4 and thereafter of this Agreement.

4. AGREEMENT

Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit, or a claim by a Settling Party that its position has greater or lesser merit than the position taken by any other Settling Party. This Agreement is subject to the express limitation on precedent as provided in Commission Rule 12.5 and as described in Paragraph 11. Unless specifically stated otherwise herein, this Agreement and its terms are intended to remain in effect until a decision is implemented in Phase 2 of SCE's next GRC.

A. Illustrative Rates

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the Large Power Rate Groups' share of the consolidated revenue requirement of $17,466 million described in more detail in Paragraph 4.B of the MCRA Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the MCRA Settlement Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

B. Common Rate Design Elements

Consistent with SCE's Application, rate structures for the Large Power Rate Groups will generally consist of Customer Charges, TOU Energy Charges, TRD Charges, and FRD Charges.

Default CPP rate schedules will no longer apply to the TOU-GS-3 and TOU-8 rate classes. Optional RTP rate schedules will also continue to be available. Finally, accounts eligible for legacy TOU period rate option in accordance with D.17-01-006 and D.17-10-018 will remain on Legacy Option A, Option B, and/or Option R until the end of their legacy period.

1) <u>TOU Periods and Seasonal Definitions</u>

SCE's existing TOU periods and summer/winter season definitions for C&I customers shall not be modified from their current definitions (*i.e.,* summer: June through September; winter: October through May).

2) <u>Customer Charges</u>

Customer Charges shall be derived based on SCE's as-proposed RECC customer marginal cost method, but adjusted to recover a portion (*i.e.*, the first 50 kVA) of the FLT costs in the FRD Charge. Customer Charges shall be set at the full EPMC level for all customers in the Medium and Large Power Rate Groups. Illustrative monthly Customer Charges are listed in the Table below:

Table 1: Illustrative Monthly Customer Charges

Rate Group	Customer Charge
TOU-GS-3	$1,140.50
TOU-8-SEC	$2,514.50
TOU-8-PRI	$313.25
TOU-8-SUB	$8,512.50

When this Agreement is first implemented in 2026, these estimated Customer Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MCRA Settlement Agreement.[3] Thereafter, these Customer Charges shall be adjusted on a Functional SAPC basis.

---

[3] *See* Paragraph 4.B.6 of the MCRA Settlement Agreement.

3) **Energy Charges**

Proposed Energy Charges based on SCE's 2024 consolidated revenue requirement are set forth in Appendix B.[4] When this Agreement is first implemented in 2026, these estimated Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MCRA Settlement Agreement.[5] Thereafter, these estimated Energy Charges shall be adjusted consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement when SCE's authorized revenue requirements change.

a) **Non-Generation-Related Energy Charges**

Energy Charges that are designed to recover revenues associated with the following categories -- transmission (TOTCA), distribution,[6] public purpose programs, new system generation service, nuclear decommissioning, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and the CPUC reimbursement fee -- shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the MCRA Settlement Agreement.

b) **Generation-Related Energy Charges**

Except where otherwise specified in this Agreement, generation-related Energy Charges shall be established based on the TOU marginal energy costs used in the MCRA Settlement Agreement.

4) **Demand Charges**

Demand Charges shall consist of TRD Charges and FRD Charges. TRD Charges may be differentiated by summer and winter seasons and by TOU periods. FRD Charges are not differentiated by season or TOU period.

---

[4] The estimated consolidated revenue requirement, as defined in Paragraph 4.B.1 of the MCRA Settlement Agreement, is $17,466 million.

[5] *See* Paragraph 4.B.6 of the MCRA Settlement Agreement.

[6] The recovery of distribution costs via Energy Charges varies based on the specific rate option, and is further discussed in the "Base and Optional Rates and Rate Design" section below.

a) **TRD Charges**

The base rate (*i.e.,* Option D) option for each rate class will continue to collect most generation capacity costs via TRD Charges and shall continue to apply both in the summer on-peak period and also in the winter mid-peak period.[7] The amount of generation revenues recovered via TRD Charges is discussed for each rate class in the "Base and Optional Rates and Rate Design" section below. Additionally, this Settlement Agreement continues to include distribution TRD Charges in both the summer on-peak and winter mid-peak periods. The amount of distribution revenues recovered via the distribution TRD Charges is discussed for each rate class in the "Base and Optional Rates and Rate Design" section below.

Table 2: Estimated Backup and Supplemental TRD Charges for Standby (Based on Option D)[8]

	TOU-8-S-Sec	TOU-8-S-Pri	TOU-8-S-Sub
Backup Summer On-Peak ($/kW)	$23.55	$22.04	$11.33
Backup Winter Mid-Peak $/kW	$10.37	$8.35	$5.23
Supplemental Summer On-Peak $/kW	$29.72	$30.77	$18.36
Supplemental Winter Mid-Peak $/kW	$10.19	$11.14	$9.34

Table 3: Illustrative TRD Charges (Option D)[9]

	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
Summer On-Peak ($/kW)	$29.02	$29.72	$30.77	18.36
Winter Mid-Peak ($/kW)	$8.81	$10.19	$11.14	$9.34

To offer customers a menu of rate options, this Settlement Agreement continues to make available "Option E" rates (with eligibility restrictions for the TOU-8 rate classes, as

[7] TRD charges do not apply on weekends or holidays in the winter mid-peak period.

[8] These TRD Charges combine both the generation and distribution TRD amounts; the individual components are provided in Appendix B.

[9] These TRD Charges combine both the generation and distribution TRD amounts; the individual components are provided in Appendix B.

discussed below), which include a lower generation TRD charge compared to Option D and no distribution TRD Charge. The Option E TRD Charge is set at twenty-five percent (25%) of the Standby backup demand charge for each rate class. As part of this Agreement, SCE agrees to perform a DER Class Study during the attrition year as described in Paragraph 4.K, below.

Table 4: Illustrative Generation TRD Charges (Option E)

	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
Summer On-Peak ($/kW)	$4.46	$4.48	$3.07	$2.47
Winter Mid-Peak ($/kW)	$1.68	$2.00	$1.65	$1.30

When this Agreement is first implemented, the illustrative TRD Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MCRA Settlement Agreement.[10] Thereafter, these TRD Charges shall be adjusted consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement for each individual rate class when SCE's authorized generation and distribution revenues change.

b) **<u>FRD Charges</u>**

Both Options D and E (and the Standby rate options) include a non-coincident FRD Charge (also CRC Charges for Standby), which this Agreement maintains to recover certain allocated delivery revenues, including SCE's base transmission revenues as adopted in FERC proceedings, for the TOU-GS-3, and TOU-8 rate classes. For distribution-related revenues, with the exception of the TOU-8-Sub rate class, all other rates for medium and large power rate classes utilize the FRD Charge to recover Distribution Grid-related costs and 95 percent of the off-peak distribution capacity costs in the Option D rate designs. For TOU-8-Sub, Option D, the FRD Charge recovers Distribution Grid-related costs and summer non-peak (*i.e.,* summer mid- and off-peak) distribution capacity costs. For the Option E rates, with the exception of TOU-8-Sub, 30 percent of distribution

[10] *See* Paragraph 4.B.6 of the RA Settlement Agreement.

revenues are recovered via the FRD Charge. For TOU-8-Sub, Option E, only Distribution Grid-related costs are recovered via the FRD Charge.

Table 5: Illustrative FRD Charges (Option D)

	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
FRD Charge ($/kW)	$29.50	$29.47	$30.18	$11.63

Table 6: Illustrative CRC and FRD Charges for Standby (based on Option D)

	TOU-8-S-Sec	TOU-8-S-Pri	TOU-8-S-Sub
FRD Charge ($/kW)	$29.47	$30.18	$11.63
CRC Charge ($/kW)	$23.55	$16.35	$1.20

Table 7: Illustrative FRD Charges (Option E)

	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
FRD Charge ($/kW)	$13.36	$13.90	$14.05	$10.00

5) <u>Voltage Discounts</u>

Customers served at higher voltage delivery levels than the design voltage level for their rate group will receive a voltage discount reflecting their relatively lower cost of service. SCE will establish the discount levels based on the difference in marginal costs of service between the design or predominant voltage level for a given rate group and the higher voltage service options. Voltage discounts shall apply to rate schedules in the TOU-GS-3, TOU-8, and TOU-8-S rate classes, as indicated in Appendix B. SCE will implement a refinement to the time-related demand voltage discounts. The refinement will differentiate the voltage discount into seasonal summer and winter voltage discounts for all rate options.[11] The voltage discounts are differentiated by season. The summer voltage discount is applied to the summer on-peak period and the winter voltage discount is applied to the winter mid-peak period, consistent with the way TRD charges are assessed.[12] The TOU-8 and

[11] Except for legacy rate options where the voltage discounts will be left unchanged.
[12] Voltage discounts do not apply on weekends or holidays in the winter mid-peak period.

Standby rate classes have voltage-differentiated rates, as reflected in the applicable tariffs, with the exception of service provided at the 220 kV level or higher.

6) Power Factor Adjustments

The method for determining power factor adjustment rates will be revised to more closely reflect SCE's cost of correcting poor power factor conditions, as indicated in Exhibit SCE-04. Power factor adjustments paid by certain customers shall be as proposed by SCE in its testimony, which is \$0.76 \$/kVAR for service at or above 50 kV and \$0.60/kVAR for service at less than 50 kV.[13]

7) Base Distribution Facilities Related Demand and Energy Charges Adjustments

For TOU-8 Option D rate schedules,[14] where distribution service revenue recovery is reflected through base rates that are charged on a cents per kWh basis (energy charge), and a dollar per kW basis (demand charge), SCE shall provide an offset whereby SCE will subtract from existing distribution energy charges an amount equivalent to the Fixed Recovery Charge on a cent-per-kWh basis. The revenue imbalance of distribution base revenues created by this adjustment will be recovered through a commensurate adjustment of the non-coincident peak demand charges on a dollar-per-kW basis. By making this adjustment, customers in the applicable rate classes will experience an upward adjustment to their demand charges with the offset in distribution energy charges, assuming no other changes to overall revenue requirement or revenue allocation to the class.[15]

C. Base and Optional Rates and Rate Design (Non-Standby)

1) Option D Base Rate -- Eligibility Requirements and Rate Design

a) Option D Eligibility for TOU-GS-3

Existing eligibility requirements are maintained (*i.e.,* C&I customers with demands of 200 kW up to 500 kW with no other eligibility restrictions).

---

[13] Exhibit SCE-04, p. 16.

[14] This includes TOU-8-SUB.

[15] This mechanism retains the energy-only structure of the fixed recovery charge approved in D.20-11-007 and D.21-10-025, while satisfying EPUC's request for a distribution demand charge adjustment. *See e.g.*, D.20-11-007 at 80 ("we find that EPUC's request for a demand charge should be addressed in SCE's upcoming [2021] GRC Phase 2 proceeding or some other appropriate proceeding as the Commission may designate.").

b) Option D Rate Design for TOU-GS-3

Option D incorporates the following rate design:

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge of $1,140.50/month (TOU-GS-3).
- For distribution, a summer on-peak TRD Charge that recovers summer on-, mid- and five percent (5%) of off-peak capacity costs; a winter mid-peak TRD charge that recovers all winter peak capacity costs; and the use of an FRD Charge to recover Grid-related costs and ninety-five (95%) of summer off-peak capacity costs.
- For generation, summer on-peak costs are recovered via the Summer on-peak TRD and all winter capacity costs are recovered via winter mid-peak TRD Charges. Summer mid- and off-peak capacity costs are included in summer on- and mid-peak energy charges. Generation energy costs are recovered via volumetric TOU Energy Charges.

c) Option D Eligibility for TOU-8

Existing eligibility requirements are maintained (*i.e.,* C&I customers with demands exceeding 500 kW but excluding certain large water pumping and agricultural customers).

d) Option D Rate Design for TOU-8

Option D incorporates the following rate design for *TOU-8-Sec* and *TOU-8-Pri*:

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge as set forth in Appendix B hereto.
- For distribution, a summer on-peak TRD Charge that recovers summer on, mid- and five percent (5%) of off-peak capacity costs, a winter mid-peak TRD Charge that recovers all winter peak capacity

costs, and the use of an FRD Charge to recover Grid-related costs and ninety-five percent (95%) of summer off-peak capacity costs

- For generation, the rate design is consistent with the generation rate design for Option D of the TOU-GS-3 rate class, as described above.

Option D incorporates the following rate design for *TOU-8-Sub*:

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge as set forth in Appendix B hereto.
- For distribution, a summer on-peak TRD Charge that recovers summer on-peak capacity costs, a winter mid-peak TRD charge that recovers all winter capacity costs, and an FRD Charge that recovers Grid-related costs and summer mid- and off-peak capacity costs (no distribution costs are recovered via Energy Charges).
- For generation, the rate design is consistent with the generation rate design for Option D of the TOU-GS-3 rate class, as described above.

2) Option E Optional Rate – Eligibility Requirements and Rate Design

a) Option E Eligibility for TOU-GS-3

The current eligibility criteria (*i.e.*, C&I customers with demands above 200 kW up to 500 kW) is retained for this Settlement Agreement. Customers both with and without DERs are also eligible for Option E, and those receiving service on Option E are exempt from being required to take service on a Standby rate schedule.

b) Option E Rate Design for TOU-GS-3

Option E incorporates the following rate design:

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge of $1,140.50/month.
- For distribution, recovery of sixty percent (60%) of revenues (excluding Customer Charge revenues) via TOU Energy Charges

using SCE's as-proposed PLRFs, thirty percent (30%) via an FRD Charge, and ten percent (10%) via flat cent-per-kWh Energy Charges.

- For generation, recovery of energy and capacity revenues is via a TRD Charge set at twenty-five percent (25%) of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

c) <u>TOU-GS-3 Energy Rate Scalar</u>

In addition to the rate design structure described above, Settling Parties agree that an energy rate scalar shall be applied to the TOU-GS-3 Option E energy charge to capture some of the revenue responsibility shift associated with customers participating on Option E.
The energy scalar is set to recover twenty-five percent (25%) of revenue responsibility shift within the TOU-GS-3 Option E customer group. The revenue responsibility shift is calculated by measuring the difference between the EPMC scaled marginal cost revenue responsibility and the revenue recovered from the non-scaled revenue of Option E customers at Option E rate. The energy scalar applied to TOU-GS-3 Option E will be TOU-shaped to preserve the TOU differential designed in the revenue neutral Option E. The scalar shall remain fixed during the attrition years once established during the implementation of the 2025 GRC Phase 2 Decision.

d) <u>Option E Eligibility for TOU-8</u>

- Option E eligibility is limited to customers who:
    - Participate in PLS (eligible systems must account for at least 15 percent of the customer's annual peak demand, as recorded over the previous 12 months), cold ironing pollution mitigation programs or the charging of eligible ZEVs intended for the transport of people or goods.
    - Install, own, or operate solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by CSI or SGIP, including paired storage systems.

An eligible customer’s system must have a net renewable generating capacity equal to or greater than 15 percent of the customer’s annual peak demand, as recorded over the previous 12 months.

  - Install standalone storage. An eligible customer’s system must have a minimum discharge capacity equal to or greater than 20 percent of the customer’s annual peak demand, as recorded over the previous 12 months.

- Eligibility for Option E is further limited to customers with annual peak demands not exceeding 5 MWs.
- Customers receiving service on Option E are exempt from being required to take service on a Standby rate schedule.
- A 250 MW participation cap will be maintained for customers with DER technologies. The capacity of new and existing customers who are utilizing PLS, cold-ironing, eligible ZEVs technologies will not be counted against the cap.
  - For DERs, the qualifying capacity counted towards the 250 MW participation cap is based on the system’s AC nameplate rating.
  - For standalone storage, the qualifying capacity counted towards the cap is the discharge capacity of the storage system.
  - For paired storage systems, the qualifying capacity counted towards the cap is the larger of the system’s AC nameplate solar capacity or the discharge capacity of the discharge storage system (but not both).
  - SCE agrees to file information-only ALs to report on the progress towards the cap. The frequency of such ALs will be one for every 50 MW of allocated capacity (based on the date of

the signed interconnection agreement for the DER) until 200 MW is reached, at which time SCE will file monthly ALs until the cap is reached. The monthly ALs will include additional data to help inform actual progress towards the cap, *e.g.,* such as how long systems have been allocated capacity under the 250 MW cap but have not yet received permission to operate (PTO).

e) <u>Option E Rate Design for TOU-8</u>

Option E rate design for *TOU-8-Sec* and *TOU-8-Pri* is identical to the rate design described above for TOU-GS-2 and TOU-GS-3 Option E.

<u>Option E for *TOU-8-Sub* incorporates the following rate design:</u>

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge as set forth in Appendix B.
- For distribution, an FRD Charge is used to recover Grid-related costs with the remaining revenue recovered via TOU Energy Charges using SCE's as-proposed PLRFs
- For generation, recovery of energy and capacity revenues is via a TRD Charge set at twenty-five percent (25%) of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

3) <u>Default Critical Peak Pricing (CPP) Rate Design</u>

The Settling Parties agree to not modify the currently effective CPP rates which reflect changes to the CPP program adopted in D.18-07-006 and D.21-03-056. The current effective rates include:

- CPP event periods shall coincide with the current TOU peak periods (*i.e.*, maximum number of CPP events up to 15 per year; shall include weekends, holidays, and weekdays from 4-9 p.m.);
- CPP event charge of $0.80/kWh;

- Bill protection will be offered to customers for up to one year.

However, Settling Parties agree to remove the default rate requirement and allow customers to opt-in to CPP. This agreement does not limit other changes to the CPP program in the attrition years.

4) Legacy Options B and R (Option A and B for Standby)

Large customers with behind-the-meter solar generation facilities who meet the requirements of D.17-01-006 and D.17-10-018 will continue to be eligible for the Legacy rate options (A, B, or R) until the end of their legacy periods.[16] Eligible solar customers may be served on legacy rates for ten years from their individual PTO dates, but not to exceed July 31, 2027 (non-public agencies) or December 31, 2027 (public agencies), as established in D.17-01-006 and D.17-10-018. No structural changes to the Legacy Options are adopted in this Agreement.

D. Standby Rate Design

1) Large Power

Standby customers with demands of more than 500 kW are classified into three rate classes, which are differentiated by the voltage at which service is provided. These rate groups are designated as TOU-8-Standby-Sec, TOU-8-Standby-Pri, and TOU-8-Standby-Sub. Standby customers with demands of more than 500 kW who elect service under a RTP option will be placed on Schedule TOU-8-RTP-S. The method for determining standby billing attributes (*i.e.*, Standby Demand and Supplemental Contract Capacity) used in SCE's Standby rate was fundamentally altered in SCE's 2015 GRC Phase 2 (approved by D.16-03-030). This Settlement Agreement does not structurally change the Standby rate design, nor does it change the method for determining billing attributes. Instead, in this Settlement Agreement, the Parties agree that for TOU-8-S and TOU-8-RTP-S Standby customers, the rate designs will be aligned with the changes for the Option D rates described above. SCE will continue to apply the Algorithm adopted in the 2015 GRC Phase 2 to determine Standby Demand and Supplemental Contract Capacity.

---

[16] Legacy customers would migrate off Legacy rates in October through December of 2027.

a) <u>TOU-8-LG RES-BCT Service for Customers with Demands Greater than 500 kW</u>

The Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) program is statutorily mandated and requires SCE to offer a tariff that allows local governments and campuses to generate electricity from an eligible renewable generating facility for their own use, and to export energy not consumed at the time of generation to SCE's grid. All such generation exported to SCE's grid is converted into bill credits and applied to benefiting accounts as designated by the local government or campus. RES-BCT service does not represent a form of NEM service, and thus customers taking RES-BCT service are not exempt from Standby service. Eligibility for Schedule TOU-8 Standby Option LG will continue to be limited to customers taking service on Schedule RES-BCT (*i.e.*, the generating account only). This RES-BCT Option will be closed to new customers (in all rate groups eligible for this option) upon SCE reaching 125 MW of eligible installed capacity, representing SCE's designated share of the 250 MW statewide RES-BCT capacity cap.

i. <u>TRD Charges</u>

TRD Charges for TOU-8 Standby, Option LG will apply only to Backup Service and shall be designed consistent with the TRD Charges for Option D for the corresponding TOU-8 rate classes.

ii. <u>Energy Charges</u>

All kWh usage for Standby Service, whether for Supplemental, Backup, or Maintenance Service, will be charged Supplemental Energy Charges that are determined consistent with the Energy Charges for the corresponding TOU-8 rate classes. The energy rates for Schedule TOU-8 Standby, Option LG, shall be structured to recover Supplemental generation-related capacity costs, in addition to generation-related energy costs, through volumetric Energy Charges on a cents-per-kWh basis.

2) <u>Standby Power</u>

Standby customers whose demands are 500 kW or lower will be treated similarly to customers in the TOU-8-S rate classes, with respect to the general applicability of Standby Service and determination of billing determinants. However, such customers will be served on rate schedules within their applicable rate groups with rider charges for Standby service. The Standby CRC shall be the lesser of the FRD Charge that is based on the customer's OAT or the Standby CRC specified for the TOU-8-S-Sec rate class. For standard Standby service, the underlying Base service will be taken on Option D. RES-BCT customers (*i.e.*, the Generating Account) with demands of 500 kW or lower will continue to be allowed to take Standby service on an underlying Option E rate schedule.

E. Real Time Pricing (RTP) Rate Options (including TOU-8-RTP / TOU-8-RTP-S)

The RTP rate options shall continue to reflect the changes adopted in D.18-07-006.[17] Illustrative rates reflecting these changes and modifications to make the rates revenue neutral to the applicable rate classes are included in Appendix B.

F. Schedule TOU-8-RBU (Reliability Back-up Service)

Schedule TOU-8-RBU provides customers with a service connection in addition to the customer's regular service connections, which is to be used solely for reliability or "back-up" purposes. The rate includes a nominal Customer Charge, Energy Charges, and generation TRD Charges, with no recovery of Distribution Design Demand charges in Energy or FRD Charges. The additional meter and service connection are installed in accordance with the Added Facilities provisions of SCE's Rule 2. This schedule shall be retained with adjustments to charges that are consistent with other schedules in the TOU-8 rate class.

G. Departing Load – Non-Bypassable Charges (DL-NBC)

The Settling Parties agree that Departing Load Non-Bypassable Charges the DL-NBC tariff shall be updated to reference Public Utilities Code section 2827-2827.10 in order to clarify that all renewable resources eligible for Net Energy Metering as defined in statute are treated consistently under Schedule DL-NBC.

[17] This Settlement Agreement does not address or resolve the Real Time Pricing rate design proposals raised by JARP and SBUA.

H. **Optimal Billing Period**

The Optimal Billing Period shall be retained, allowing customers to align their billing and production cycles twice within a six-month period.

I. **Demand Response Credits (APS and BIP)**

Rate structures and rate designs associated with SCE's demand response programs, *e.g.*, BIP and APS, shall reflect the respective incentive budgets at the current level as shown in Appendix B. BIP credits will continue to be provided based on the difference between the customer's summer and winter average on- and mid-peak demand and firm service level, where the average on- and mid-peak demands, in each season, are calculated by dividing the kWh usage in the period by the number of hours in the period. Illustrative rates are included in Appendix B.

J. **Implementing Future Revenue Changes in Rates**

As described in the MCRA Settlement Agreement,[18] when SCE's authorized revenues change in the future, SCE will first adjust rate levels for the default rate schedules (without CPP elements), *e.g.*, Schedules TOU-GS-3-D, and Schedule TOU-8-Sec-D, using a Functional SAPC adjustment. SCE will then rebalance optional rate levels to ensure revenue neutrality between the default rate schedule and the optional rate schedules within each rate class. For example, generation revenue changes resulting from SCE's ERRA proceedings shall be allocated on a Functional SAPC basis; *i.e.*, the revised SCE generation revenue requirement will be allocated by applying a generation-level SAPC scalar to the relevant generation-related charges, based on the difference between present rate revenues and proposed rate revenues for the default rate schedules. The optional rate schedules will then be adjusted to ensure revenue neutrality on a functional basis within each rate class, except for TOU-GS-3 as specified in Paragraph 4.C.2 above.

---

[18] *See* Paragraph 4.B.7 of the RA Settlement Agreement.

5. IMPLEMENTATION OF SETTLEMENT AGREEMENT

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1, 2026.

6. INCORPORATION OF COMPLETE AGREEMENT

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties. If the Commission does not approve this Agreement without modification, the terms and conditions reflected in this Agreement shall no longer apply to the Settling Parties.

7. RECORD EVIDENCE

The Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

8. SIGNATURE DATE

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

9. REGULATORY APPROVAL

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's Test Year 2025 GRC. The Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Settling Parties shall jointly request that the

Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

10. COMPROMISE OF DISPUTED CLAIMS

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

11. NON-PRECEDENTIAL

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Settlement Agreement is not precedential in any other pending or future proceeding before this Commission.

The Large Power Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2025 GRC, or earlier if invited to do so by the Commission in, for example, a relevant Rulemaking proceeding.

12. PREVIOUS COMMUNICATIONS

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to the subject matter of this Settlement Agreement. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

13. <u>NON-WAIVER</u>

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

14. <u>EFFECT OF SUBJECT HEADINGS</u>

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

15. <u>GOVERNING LAW</u>

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. <u>NUMBER OF ORIGINALS</u>

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: August 25, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Daniel Hopper

By: Daniel Hopper
Title: Managing Director, Regulatory Policy

Dated: August 25, 2025

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

/s/ Ronald Liebert

By: Ronald Liebert
Title: Attorney

Dated: August 25, 2025

ENERGY USERS FORUM

/s/ Robert Kehrein

By: Robert Kehrein
Title: Executive Director

Dated: August 25, 2025

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Counsel

Dated: August 25, 2025

SOLAR ENERGY INDUSTRIES ASSOCIATION

/s/ Jeanne Armstrong

By: Jeanne Armstrong
Title: Senior Regulatory Counsel

Dated: August 25, 2025

ENERGY PRODUCERS AND USERS COALITION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Counsel

Dated: August 25, 2025

ELECTRIFY AMERICA, LLC

/s/ Steve Bright

By: Steve Bright
Title: Senior Counsel

Dated: August 25, 2025

WALMART INC.

/s/ Julie Clark

By: Julie Clark
Title: Attorney

Appendix A

Comparison Of Party Positions On Large Power Rate Group Rate Design Issues and Settlement

Comparison of Positions
Large Power Rate Design Issues[1]

Issue	SCE	CLECA	SEIA	2025 GRC Settled Position
Option D Eligibility for TOU-GS-3 (<500 kW) (Base Rate)	• C&I customers with demands of >200 kW to 500 kW, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal to maintain existing eligibility requirements
Option D Rate Design for TOU-GS-3 (<500 kW) (Base Rate)	• Offer Option D based on settled rate design that incorporates: • Current TOU periods; • Customer Charge: *See Appendix B* • For distribution, summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; TOU Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs • For generation, use SCE's proposal	• Rate Design should be based on cost-of-service principles using updated marginal costs. The residual amount between the marginal cost revenues and full revenue requirement for distribution and generation should be assigned on an equal percent basis to the individual rate components • Recommends marginal costs that increase generation demand charges somewhat relative to current levels • Oppose SCE's proposal to adopt a flat energy charge across all TOU periods to pick up the remaining revenue responsibility. CLECA recommends that the energy charges be collected only during the summer TOU periods although the charge should be the same during each of the summer TOU periods	Not Addressed	• Offer Option D based on settled rate design that incorporates: • Current TOU periods; • Customer Charge: *See Appendix B* • For distribution, a summer on-peak TRD Charge that recovers summer on-, mid- and five percent (5%) of off-peak capacity costs; a winter mid-peak TRD charge that recovers all winter peak capacity costs; and the use of an FRD Charge to recover Grid-related costs and ninety-five (95%) of summer off-peak capacity costs. • For generation, use SCE's proposal
Option D Eligibility for TOU-8 (>500 kW) (Base Rate)	• C&I customers with demands >500 kW with the exception of certain large water pumping and agricultural customers, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal to maintain existing eligibility requirements
Option D Rate Design for TOU-8 (>500 kW) (Base Rate)	<u>TOU-8-SEC / TOU-8-PRI</u> • Offer Option D based on settled rate design that incorporates: • Current TOU periods; • Customer Charge: *See Appendix B* • For distribution, summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; TOU Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs • For generation, use SCE's proposal	• Rate Design should be based on cost-of-service principles using updated marginal costs. The residual amount between the marginal cost revenues and full revenue requirement for distribution and generation should be assigned on an equal percent basis to the individual rate components • Recommends marginal costs that increase generation demand charges somewhat relative to current levels • Oppose SCE's proposal to adopt a flat energy charge across all TOU periods to pick up the remaining revenue responsibility. CLECA recommends that the energy charges be collected		<u>TOU-8-SEC / TOU-8-PRI</u> • Offer Option D based on settled rate design that incorporates: • Current TOU periods; • Customer Charge: *See Appendix B* • For distribution, a summer on-peak TRD Charge that recovers summer on, mid- and five percent (5%) of off-peak capacity costs, a winter mid-peak TRD Charge that recovers all winter peak capacity costs, and the use of an FRD Charge to recover Grid-related costs and ninety-five percent (95%) of summer off-peak capacity costs • For generation, use SCE's proposal <u>TOU-8-SUB</u>

[1] Note that this comparison does not include the medium and large power rate design issues not covered by this agreement, namely the Real Time Pricing rate design proposals raised by the JARP and SBUA and SEIA's proposal to implement an Option S storage rate with daily demand charges.

Issue	SCE	CLECA	SEIA	2025 GRC Settled Position

	TOU-8-SUB
	• Offer SCE's proposed Option D based on rate design that incorporates:
	  • Current TOU periods;
	  • Customer Charge: *See Appendix B*
	  • For distribution, summer on-peak TRD Charge that recovers summer on-peak capacity cost; winter mid-peak TRD charge that recovers all winter mid-peak capacity cost; FRD Charge that recovers grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs; no distribution costs recovered via Energy Charges
	• For generation, use SCE's proposal
		only during the summer TOU periods although the charge should be the same during each of the summer TOU periods		• Offer SCE's proposed Option D based on rate design that incorporates:
				  • Current TOU periods;
				  • Customer Charge: *See Appendix B*
				  • For distribution, a summer on-peak TRD Charge that recovers summer on-peak capacity costs, a winter mid-peak TRD charge that recovers all winter capacity costs, and an FRD Charge that recovers Grid-related costs and summer mid- and off-peak capacity costs (no distribution costs are recovered via Energy Charges)
				  • For generation, use SCE's proposal

Option E Eligibility for TOU-GS-3 (200 to 500 kW) (Base Rate)	• C&I customers with demands of >200 kW to 500 kW, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	• Adopt SCE's proposal that includes no eligibility restrictions • Exempt customers with DER technologies from Standby

Option E Rate Design for TOU-GS-3 (200 to500 kW) (Base Rate)	• Adopt SCE's Option E rate design that incorporates:
	  • Current TOU periods
	  • Customer Charge: *See Appendix B*
	  • For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
	  • For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges
	  • In addition to the rate design structure described above, Settling Parties agree that an energy rate scalar shall be applied to the TOU-GS-3 Option E energy charge to capture some of the revenue responsibility shortfall associated with customers participating on Option E. The energy scalar is set to recover twenty-five percent (25%) of revenue responsibility shortfall within the TOU-GS-3 Option E customer group.
		• SCE should develop the Option E rates on the billing determinants for the Option E customer group and not on the entire customer class. To do otherwise creates a cost shift from Option E customers to other customers, which is unfair. If Option E rates are improperly set, the Option E customers will have an inadequate price signal directing them to shift load away from the on-peak periods. Furthermore, as the number of Option E customers grows, the cost shift to other customers will similarly grow.	• The role of NCDCs in recovering dist costs should be reduced in Option E rates. Recommends recovery adj to 60% via TOU cents/kWh energy charges, 20% FRD charges, & 20% w/ flat equal cent/kWh energy charges.	• Adopt SCE's Option E rate design that incorporates:
				  • Current TOU periods
				  • Customer Charge: *See Appendix B*
				  • For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
				  • For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges

Issue	SCE	CLECA	SEIA	2025 GRC Settled Position
Option E Eligibility for TOU-8 (>500 kW) (Base Rate)	• Propose no change to eligibility requirement	Not Addressed	Not Addressed	○ Adopt SCE's current TOU-8 Option Eligibility ○ SCE to continue to file information-only advice letters (ALs) to report on the progress toward the 250 MW cap; frequency will be every 50 MW of allocated capacity (based on signed interconnection agreement data and date) until 200 MW is reached, at which time SCE will file ALs monthly until the 250 MW cap is reached (the monthly filings will include addl data about projects still pending PTO)

Option E Rate Design for TOU-8 (>500 kW) (Base Rate)	<u>TOU-8-SEC / TOU-8-PRI</u>
	• Adopt SCE Option E rate design proposal that incorporates:
	  • Current TOU periods;
	  • Customer Charge: *See Appendix B*
	  • For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
	  • For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges
	<u>TOU-8-SUB</u>
	• Adopts SCE Option E rate design proposal that incorporates:
	  • Current TOU periods;
	  • Customer Charge: *See Appendix B*
	  • For distribution, grid-related costs are recovered via an FRD charge and peak-related costs are recovered via TOU Energy Charges using SCE's as-proposed PLRFs
	  • For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges
		• SCE should develop the Option E rates on the billing determinants for the Option E customer group and not on the entire customer class. To do otherwise creates a cost shift from Option E customers to other customers, which is unfair. If Option E rates are improperly set, the Option E customers will have an inadequate price signal directing them to shift load away from the on-peak periods. Furthermore, as the number of Option E customers grows, the cost shift to other customers will similarly grow.
		• Commission should direct SCE to adopt an Option E rate based on Option E customer billing determinant for each of the TOU-8 schedules once the number of Option E customers on that schedule exceeds 15 customers
			• The role of NCDCs in recovering dist costs should be reduced in Option E rates. Recommends recovery adj to 60% via TOU cents/kWh energy charges, 20% FRD charges, & 20% w/ flat equal cent/kWh energy charges.	<u>TOU-8-SEC / TOU-8-PRI</u>
				• Adopt SCE Option E rate design proposal that incorporates:
				  • Current TOU periods;
				  • Customer Charge: *See Appendix B*
				  • For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
				  • For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges
				
				<u>TOU-8-SUB</u>
				• Adopts SCE Option E rate design proposal that incorporates:
				  • Current TOU periods;
				  • Customer Charge: *See Appendix B*
				  • For distribution, grid-related costs are recovered via an FRD charge and peak-related costs are recovered via TOU Energy Charges using SCE's as-proposed PLRFs
				  • For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges

Real Time Pricing (RTP)	• Propose no structural change to existing RTP structure	Not Addressed	Not Addressed	• Adopt SCE's proposal
Standby Rates (Schedule S, TOU-8-S, TOU-8-RTP-S)	• No structural changes proposed for Schedule S • Incorporate the Option D rate design described above for TOU-8-S and TOU-8-RTP-S	Not Addressed	Not Addressed	• The rate designs will be aligned with the settled changes for the Option D rates described above
Reliability Back-Up Service (TOU-8-RBU)	• Same as Current Treatment but with updated Customer Charge, TOU Energy and TRD Charge to reflect marginal-cost based changes made to Option D (as described above)	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal

Issue	SCE	CLECA	SEIA	2025 GRC Settled Position
DL-NBC Tariff	• N/A	• Tariff should be clarified to say that all renewable resources eligible for NEM/NBT are treated consistently under tariff.	Not Addressed	• Adopt changes to special condition 1 of the DL-NBC to clarify that all renewable resources eligible for Net Energy Metering as defined in statute are treated consistently
TOU-BIP	• No structural changes proposed • The overall level of credits (*e.g.* incentives) for participants was approved in D.17-12-003. Current TOU-BIP credits are based on avoided capacity valuation approved in D.17-12-003, and updated to align with the underlying base rates (*i.e.*, Option D rate). • SCE will subsequently align TOU-BIP credits with the underlying base rates once key attributes are approved in this application	Not Addressed	Not Addressed	• BIP shall reflect the incentive budgets at the current level as shown in Appendix B. BIP credits will continue to be provided based on the difference between the customer's summer and winter average on- and mid-peak demand and firm service level, where the average on- and mid-peak demands, in each season, are calculated by dividing the kWh usage in the period by the number of hours in the period. Illustrative rates are included in Appendix B.
Solar Legacy Rates (Legacy Options B and R for non-standby, Options A and B for standby)	• Maintain same eligibility, duration, rate options, and rate structures from the 2018 GRC.	Not Addressed	Not Addressed	• Maintain same eligibility, duration, rate options, and rate structures from the 2021 GRC.
Facilities Related Demand and Energy Charges Adjustments	• For TOU-8 Option D rate schedules, where distribution service revenue recovery is reflected through base rates that are charged on a cents per kWh basis (energy charge), and a dollar per kW basis (demand charge), SCE shall provide an offset whereby SCE will subtract from existing distribution energy charges an amount equivalent to the Fixed Recovery Charge on a cent-per-kWh basis. The revenue imbalance of distribution base revenues created by this adjustment will be recovered through a commensurate adjustment of the non-coincident peak demand charges on a dollar-per-kW basis. By making this adjustment, customers in the applicable rate classes will experience an upward, or downward, adjustment to their demand charges with the offset in distribution energy charges, assuming no other changes to overall revenue requirement or revenue allocation to the class.	Not Addressed	Not Addressed	• Maintain from the settled 2021 GRC position.

Appendix B

Illustrative Large Power Rate Group Rates

Table1
Illustrative Rates TOU-GS-3-D

	TOU-GS-3 Option D									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$702.22			$702.22		$1,140.50			$1,140.50
On-MWh	(0.00004)	0.01722	0.10608	0.03403	$0.15729	(0.00004)	0.00015	0.10115	0.03472	$0.13598
Mid-MWh	(0.00004)	0.01567	0.09673	0.03403	$0.14639	(0.00004)	0.00015	0.08313	0.03472	$0.11795
Off-MWh	(0.00004)	0.01536	0.06533	0.03403	$0.11468	(0.00004)	0.00015	0.06733	0.03472	$0.10215
SOff-MWh										
On-MW		19.04	18.22		$37.26		13.09	15.93		$29.02
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	4.23	19.04			$23.27	4.23	25.27			$29.50
Winter										
Customer Charge		$702.22			$702.22		$1,140.50			$1,140.50
On-MWh										
Mid-MWh	(0.00004)	0.01722	0.07539	0.03403	$0.12660	(0.00004)	0.00015	0.07529	0.03472	$0.11011
Off-MWh	(0.00004)	0.01567	0.07585	0.03403	$0.12551	(0.00004)	0.00015	0.08076	0.03472	$0.11558
SOff-MWh	(0.00004)	0.01479	0.03983	0.03403	$0.08861	(0.00004)	0.00015	0.04438	0.03472	$0.07920
On-MW										
Mid-MW		3.38	6.59		$9.97		2.09	6.72		$8.81
Off-MW										
SOff-MW										
Max-MW	4.23	19.04			$23.27	4.23	25.27			$29.50

Table2
Illustrative Rates TOU-GS-3-E

	TOU-GS-3 Option E									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$702.22			$702.22		$1,140.50			$1,140.50
On-MWh	(0.00004)	0.38525	0.31348	0.03403	$0.73272	(0.00004)	0.35034	0.28430	0.03457	$0.66918
Mid-MWh	(0.00004)	0.20210	0.09673	0.03403	$0.33282	(0.00004)	0.33596	0.08313	0.03457	$0.45363
Off-MWh	(0.00004)	0.10096	0.06533	0.03403	$0.20028	(0.00004)	0.09464	0.06733	0.03457	$0.19649
SOff-MWh										
On-MW			5.11		$5.11			4.46		$4.46
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	4.23	9.65			$13.88	4.23	9.13			$13.36
Winter										
Customer Charge		$702.22			$702.22		$1,140.50			$1,140.50
On-MWh										
Mid-MWh	(0.00004)	0.03367	0.12139	0.03403	$0.18905	(0.00004)	0.02569	0.13834	0.03457	$0.19856
Off-MWh	(0.00004)	0.01375	0.07585	0.03403	$0.12359	(0.00004)	0.01492	0.08076	0.03457	$0.13021
SOff-MWh	(0.00004)	0.02766	0.03983	0.03403	$0.10148	(0.00004)	0.03131	0.04438	0.03457	$0.11021
On-MW										
Mid-MW			2.72		$2.72			1.68		$1.68
Off-MW										
SOff-MW										
Max-MW	4.23	9.65			$13.88	4.23	9.13			$13.36

Table 3
Illustrative Rates for TOU-8-D Secondary

	TOU-8-SEC Option D									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$460.86			$460.86		$2,514.50			$2,514.50
On-MWh	(0.00004)	0.01485	0.10467	0.03370	$0.15318	(0.00004)	(0.00115)	0.10206	0.03372	$0.13459
Mid-MWh	(0.00004)	0.01340	0.09544	0.03370	$0.14250	(0.00004)	(0.00115)	0.08384	0.03372	$0.11637
Off-MWh	(0.00004)	0.01309	0.06466	0.03370	$0.11141	(0.00004)	(0.00115)	0.06760	0.03372	$0.10013
SOff-MWh										
On-MW		20.95	18.98		$39.93		13.72	16.00		$29.72
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	4.40	20.68			$25.08	4.40	25.07			$29.47
Winter										
Customer Charge		$460.86			$460.86		$2,514.50			$2,514.50
On-MWh										
Mid-MWh	(0.00004)	0.01722	0.07539	0.03370	$0.12627	(0.00004)	(0.00115)	0.07560	0.03372	$0.10813
Off-MWh	(0.00004)	0.01567	0.07585	0.03370	$0.12518	(0.00004)	(0.00115)	0.08110	0.03372	$0.11363
SOff-MWh	(0.00004)	0.01479	0.03983	0.03370	$0.08828	(0.00004)	(0.00115)	0.04451	0.03372	$0.07704
On-MW										
Mid-MW		3.59	5.82		$9.41		2.21	7.97		$10.19
Off-MW										
SOff-MW										
Max-MW	4.40	20.68			$25.08	4.40	25.07			$29.47

Table 4
Illustrative Rates for TOU-8-D Primary

	TOU-8-PRI Option D									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$475.29			$475.29		$313.25			$313.25
On-MWh	(0.00005)	0.01219	0.10020	0.03230	$0.14464	(0.00005)	(0.00103)	0.09797	0.03242	$0.12931
Mid-MWh	(0.00005)	0.01100	0.09157	0.03230	$0.13482	(0.00005)	(0.00103)	0.08064	0.03242	$0.11198
Off-MWh	(0.00005)	0.01077	0.06191	0.03230	$0.10493	(0.00005)	(0.00103)	0.06366	0.03242	$0.09500
SOff-MWh										
On-MW		18.83	18.25		$37.08		13.68	17.09		$30.77
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	4.36	20.00			$24.36	4.36	25.82			$30.18
Winter										
Customer Charge		$475.29			$475.29		$313.25			$313.25
On-MWh										
Mid-MWh	(0.00005)	0.01219	0.07160	0.03230	$0.11604	(0.00005)	(0.00103)	0.07145	0.03242	$0.10279
Off-MWh	(0.00005)	0.01100	0.07220	0.03230	$0.11545	(0.00005)	(0.00103)	0.07680	0.03242	$0.10814
SOff-MWh	(0.00005)	0.01025	0.03788	0.03230	$0.08038	(0.00005)	(0.00103)	0.04215	0.03242	$0.07349
On-MW										
Mid-MW		3.40	6.83		$10.23		2.33	8.81		$11.14
Off-MW										
SOff-MW										
Max-MW	4.36	20.00			$24.36	4.36	25.82			$30.18

Table 5
Illustrative Rates for TOU-8-E Primary

	TOU-8-PRI Option E									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$475.29			$475.29		$313.25			$313.25
On-MWh	(0.00005)	0.31408	0.28457	0.03230	$0.63090	(0.00005)	0.27747	0.28727	0.03242	$0.59711
Mid-MWh	(0.00005)	0.16454	0.09157	0.03230	$0.28836	(0.00005)	0.25012	0.08064	0.03242	$0.36313
Off-MWh	(0.00005)	0.07304	0.06191	0.03230	$0.16720	(0.00005)	0.06644	0.06366	0.03242	$0.16247
SOff-MWh										
On-MW			4.47		$4.47			3.07		$3.07
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	4.36	9.73			$14.09	4.36	9.69			$14.05
Winter										
Customer Charge		$475.29			$475.29		$313.25			$313.25
On-MWh										
Mid-MWh	(0.00005)	0.02728	0.13084	0.03230	$0.19037	(0.00005)	0.01897	0.14328	0.03242	$0.19462
Off-MWh	(0.00005)	0.01038	0.07220	0.03230	$0.11483	(0.00005)	0.01009	0.07680	0.03242	$0.11926
SOff-MWh	(0.00005)	0.02171	0.03788	0.03230	$0.09184	(0.00005)	0.02375	0.04215	0.03242	$0.09827
On-MW										
Mid-MW			0.78		$0.78			1.65		$1.65
Off-MW										
SOff-MW										
Max-MW	4.36	9.73			$14.09	4.36	9.69			$14.05

Table 6
Illustrative Rates for TOU-8-D Subtrans

	TOU-8-SUB Option D									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$4,951.05			$4,951.05		$8,512.50			$8,512.50
On-MWh	(0.00005)	(0.00052)	0.09391	0.02696	$0.12030	(0.00005)	(0.00052)	0.08474	0.02955	$0.11372
Mid-MWh	(0.00005)	(0.00052)	0.08606	0.02696	$0.11245	(0.00005)	(0.00052)	0.07000	0.02955	$0.09898
Off-MWh	(0.00005)	(0.00052)	0.05786	0.02696	$0.08425	(0.00005)	(0.00052)	0.05495	0.02955	$0.08393
SOff-MWh										
On-MW		8.11	20.14		$28.25		2.80	15.56		$18.36
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	4.42	7.30			$11.72	4.42	7.21			$11.63
Winter										
Customer Charge		$4,951.05			$4,951.05		$8,512.50			$8,512.50
On-MWh										
Mid-MWh	(0.00005)	(0.00052)	0.06697	0.02696	$0.09336	(0.00005)	(0.00052)	0.06188	0.02955	$0.09086
Off-MWh	(0.00005)	(0.00052)	0.06778	0.02696	$0.09417	(0.00005)	(0.00052)	0.06674	0.02955	$0.09572
SOff-MWh	(0.00005)	(0.00052)	0.03554	0.02696	$0.06193	(0.00005)	(0.00052)	0.03665	0.02955	$0.06563
On-MW										
Mid-MW		0.93	6.51		$7.44		0.09	9.24		$9.34
Off-MW										
SOff-MW										
Max-MW	4.42	7.30			$11.72	4.42	7.21			$11.63

Table 7
Illustrative Rates for TOU-8-E Subtrans

	TOU-8-SUB Option E									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$4,951.05			$1,140.50		$8,512.50			$1,140.50
On-MWh	(0.00005)	0.10141	0.31263	0.02696	$0.44095	(0.00005)	0.03284	0.24139	0.02955	$0.30373
Mid-MWh	(0.00005)	0.05892	0.08606	0.02696	$0.17189	(0.00005)	0.06935	0.07000	0.02955	$0.16885
Off-MWh	(0.00005)	0.01464	0.05786	0.02696	$0.09941	(0.00005)	0.00561	0.05495	0.02955	$0.09006
SOff-MWh										
On-MW			1.91		$1.91			2.47		$2.47
Mid-MW										
Off-MW										
SOff-MW										
Max-MW	4.42	3.90			$8.32	4.42	5.58			$10.00
Winter										
Customer Charge		$4,951.05			$4,951.05		$8,512.50			$8,512.50
On-MWh										
Mid-MWh	(0.00005)	0.00830	0.11471	0.02696	$0.14992	(0.00005)	(0.00018)	0.12903	0.02955	$0.15835
Off-MWh	(0.00005)	0.00098	0.06778	0.02696	$0.09567	(0.00005)	(0.00052)	0.06674	0.02955	$0.09572
SOff-MWh	(0.00005)	0.00177	0.03554	0.02696	$0.06422	(0.00005)	(0.00024)	0.03665	0.02955	$0.06591
On-MW										
Mid-MW			0.93		$0.93			1.30		$1.30
Off-MW										
SOff-MW										
Max-MW	4.42	3.90			$8.32	4.42	5.58			$10.00

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

ECONOMIC DEVELOPMENT RATE SETTLEMENT AGREEMENT

Dated: **September 10, 2025**

ECONOMIC DEVELOPMENT RATE SETTLEMENT AGREEMENT

Table of Contents

Section **Page**

ECONOMIC DEVELOPMENT RATE SETTLEMENT AGREEMENT

Table of Contents (Continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

ECONOMIC DEVELOPMENT RATE SETTLEMENT AGREEMENT

This Economic Development Rate (EDR) Settlement Agreement (Agreement or Settlement Agreement) is entered into by and among the undersigned Parties hereto, with reference to the following:

1. Parties

The Parties to this Agreement are Southern California Edison Company (SCE); The Utility Reform Network (TURN); the California Large Energy Consumers Association (CLECA); California Manufacturers & Technology Association (CMTA); Energy Users Forum (EUF); Walmart Inc., and the Small Business Utility Advocates (SBUA) (referred to hereinafter collectively as Settling Parties or individually as a Party).

A. SCE is an investor-owned public utility (IOU) and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. CLECA is an organization of large, high voltage, high load factor industrial electric bundled service, Community Choice Aggregator (CCA) and Direct Access (DA) customers located throughout the state. These companies are in the steel, cement, industrial and medical gas, beverage, minerals processing, cold storage, and pipeline transportation industries, and share the fact that electricity costs comprise a significant portion of their cost of production.

C. CMTA is a trade association representing the interests of 25,000 large and small manufacturers in California and 1.2 million employees. Many of its members receive electrical service from SCE as either bundled service or DA customers.

D. EUF is an *ad hoc* group that represents the interests of medium and large bundled service, DA, and CCA customers in California, taking service on rate schedules for accounts with demand above approximately 50 kW.

E. TURN is an independent, non-profit consumer advocacy organization that represents the interests of residential and small commercial utility customers.

F. SBUA is a nonprofit organization that represents, protects, and promotes the interests of the small business utility customers.

G. Walmart Inc. is a multinational retail corporation that operates 303 retail units, 17 distribution centers, and four fulfillment centers and employs over 104,000 associates in California.

2. <u>Definitions</u>

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "BPU" means Base Period Usage and is an average of Customer's historical monthly energy usage (kWh) and demand (kW) (provided Customer is served on an OAT with demand charges) by season and time-of-use where applicable, and is computed by SCE from Customer's 12 most representative continuous months of usage out of the past 24 months.

B. "But For Affidavit" means a sworn affidavit signed by an EDR applicant stating that but for the EDR discount, alone or in combination with other incentives, the customer would not retain, attract or expand its load in California (as applicable).

C. "Commission" means the California Public Utilities Commission.

D. "Discount Revenues" is the revenue shortfall associated with an EDR rate discount granted to participating customers.

E. "Incremental Load Revenues" are the revenue increases associated with new usage occurring when an EDR-A or EDR-E rate is provided, as well as the retained revenues associated with EDR-R.

F. "EDR" means Economic Development Rate.

G. "EDR Agreement" means the EDR-Retention (EDR-R), EDR-Expansion (EDR-E), or EDR-Attraction (EDR-A) Agreement.

H. "EDR Program Cap" means a total of 300 megawatts (MW) of customer load that is subject to discount pursuant to the EDR Agreements signed after this Settlement Agreement is implemented.

I. "EPCP" means Cal Advocates' Electricity Pricing and Customer Programs Branch or its successor.

J. "GRC Phase 2" means the regulatory proceeding in which the Commission adopts marginal costs, revenue allocation, and rate designs that will ultimately be applied to SCE's authorized revenue requirements. The proceeding relates to, but is separate from, Phase 1 of the general rate case (GRC) proceeding, which is SCE's triennial request to increase it Commission-authorized revenues.

K. "Small Customer Account" shall mean a non-residential, non-governmental customer account with load below 201 kilowatts (kW).

3. **Recitals**

A. The Commission first authorized EDR tariffs for SCE in Decision (D.) 96-08-025 as a way of offering incentives to large, non-governmental, non-residential SCE customers who would otherwise not retain, expand, or locate their load in California. Then, in D.05-09-018, as modified by D.07-09-016 and D.07-11-052, the Commission approved a second vintage of EDRs for SCE (and for Pacific Gas and Electric Company, or PG&E) with a sunset date of December 2009.

B. In D.10-06-015, as modified by D.11-05-029, the Commission approved a settlement agreement between SCE, PG&E and several other parties for a new 200 MW EDR program (for each of SCE and PG&E) that closed to new customers on December 31, 2012.

C. On August 19, 2014, the Commission issued Resolution E-4675 approving SCE's unopposed Tier 3 Advice Letter seeking authority to implement interim EDRs subject to a 200 MW program during the period when a related SCE EDR application (A.14-03-013) was pending.

D. In D.15-04-006, the Commission approved a settlement agreement between SCE and ORA resolving A.14-03-013, in which the parties agreed to another 200 MW EDR program. The term of the settlement agreement adopted in D.15-04-006 expired on the date on which SCE's tariffs implemented the 2018 GRC Phase 2.[1]

E. In D.18-11-027, the Commission approved SCE's current EDR program, which is based on a settlement agreement between Cal Advocates, TURN, and the Small Business Utility Advocates (SBUA).[2]

F. On December 20, 2022, the Commission granted SCE's request under Rule 16.6 of the California Public Utilities Commission's Rules of Practice and Procedure to extend the EDR program cycle date, subject to the program cap, to the earlier of the day before rates implementing the next EDR program, if any, are implemented, or the day before SCE's 2025 GRC Phase 2 rates are implemented (whichever comes first).

G. On March 29, 2024, SCE filed its 2025 GRC Phase 2 application (Application) and served supporting testimony seeking, among other relief, authorization for a new EDR program.

H. Protests and responses to SCE's Application were filed May 8, 2024. CLECA's protest recommended a higher discount (25%) than SCE's EDR proposal of 20%, along with an increase to the contract term from 5 years to 10 years.

I. A Scoping Memo and Ruling Assigned Commissioner and Administrative Law Judge was issued on November 1, 2024 identifying "economic development rate program" as a nonresidential rate design issue to be resolved in the proceeding.

J. Cal Advocates served testimony on November 22, 2024.

K. CLECA, served testimony on January 8, 2025 addressing, in part, to SCE's EDR proposal.

L. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on January 3, 2025. Continuing settlement discussions occurred among the parties after that date.

---

[1] See Paragraph 10 of *Settlement Agreement Resolving Southern California Edison Company's Application for Approval of 2014-2018 Economic Development Rates*, adopted in D.15-04-006.

[2] The parties' Settlement Agreement eliminated SCE's prior Enhanced EDR Program which provided that if a commercial customer is located in a city or county with an unemployment rate that is 125 percent or more greater than the previous year's statewide average unemployment rate, then that customer could get a 30 percent discount.

M. The Settling Parties have evaluated the impacts of the EDR testimony and competing proposals in this proceeding and desire to resolve all issues related to EDRs beginning with the implementation of a CPUC decision approving this Agreement and have reached agreement as indicated in Paragraph 4 hereof.

N. Appendix A to this Agreement provides a comparison of the Settling Parties' EDR-related positions that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and Appendix A, the terms of this Agreement shall control.

4. General Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Settlement Agreement. Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit, or a claim by a Settling Party that its position has greater or lesser merit than the position taken by any other Settling Party. This Agreement is subject to the express limitation on precedent as provided in Commission Rule 12.5 and as described in Paragraph 11.

A. Portfolio Approach

The Settling Parties agree to a new portfolio approach that allows discount revenues and incremental load revenues to be allocated within their respective portfolios. There will be three portfolios as follows:

- Portfolio 1 – Small: TOU-GS-1 rate schedule;
- Portfolio 2 – Small/Medium: TOU-GS-2 and TOU-GS-3 rate schedules;
- Portfolio 3 - Large Power: TOU-8-SEC, -PRI, -SUB rate schedule.

The Discount Revenues and Incremental Load Revenues will be allocated to the customers on the rate schedules associated with each portfolio. Rates for other customers will not be affected.

B. Term of Agreement, Contracts

Unless otherwise specified herein, the provisions of this Agreement are intended to remain in effect until a decision implementing a successor EDR program for SCE is adopted by the Commission.

The term of each five-year EDR contract is specified in the agreements included in Appendix B. In particular, the contract language for EDR attraction and expansion customers in Section 5.1 of the EDR-Expansion and EDR-Attraction shall be modified to the following:

- "SCE will begin providing the Customer service under Schedule EDR-A/EDR-E at the start of the next regular billing period following the date the Customer notifies SCE, which shall typically not be more than 24 months from the effective date of this Agreement unless the delay in commencement of service is due to SCE's need to build adequate infrastructure, in which case, the commencement date shall be the date when SCE is able to complete installation and energize new power service."
- Retention customers shall continue to be eligible to commence service on the EDR within twelve months of contract execution, or as soon as at the start of their next regular billing period following execution of the EDR contract.

C. Description of Rate Discount

SCE shall offer a flat discount of 20 percent to eligible EDR customers subject to an aggregate program cap of 300 MW (Program Cap), as agreed upon by the Settling Parties. The discount shall not be modified by a price floor for purposes of calculating the EDR customer's bill. EDR percentage discounts shall exclude generation service cost components of customer bills unless generation service is provided by SCE.

D. Program Cycle

Subject to the Program Cap, the last date a customer may execute an EDR Agreement shall be the day before rates implementing the next EDR program is implemented *or* the day before SCE's next GRC Phase 2 rates are implemented (whichever comes first).

E. Eligibility

To be eligible for an EDR Agreement, an EDR applicant must be a non-residential, non-governmental customer with load—either individually, or in the aggregate[3] across

[3] Smaller businesses are often tenants of a larger facility (in contrast to larger businesses that may occupy an entire facility as the sole tenant, or who outright own the facility).

accounts located at the same physical facility—greater than 200 kW. Notwithstanding this load threshold, Settling Parties agree to increase the total of Small Customer Accounts may take service on the EDR at any given time in the Program Cycle from 20 to 60, provided they meet the other applicable eligibility criteria discussed herein. Additionally, a participation cap of 10 incremental customers will apply to TOU-8-SUB. The total cap over the cycle will be the sum of existing TOU-8-SUB customers and the incremental cap. Finally, Settling Parties agree to the following: for new EDR applicants with loads greater than 60 MW, an FTE to load ratio (i.e., FTE/MW) greater than or equal to 1.0 is required.

To qualify for service under the rate, EDR customers must execute an EDR Agreement,[4] including execution of a But For Affidavit, and must not have taken service on an EDR previously for the same load. Other eligibility criteria are in the tariffs and agreements attached hereto. With the exception of the Small Customer Accounts, all EDR applicants must also obtain a recommendation from the California Governor's Office of Business and Economic Development (GO-Biz), or its successor entity, before they are deemed eligible to take service on an EDR.

F. <u>Scope of EDRs</u>

EDRs are intended to retain/attract/expand load in California relative to out-of-state options, and are not intended to attract customers from one service area to another within the state, or to attract out-of-state customers to one in-state electric service area or provider over another.

G. <u>Funding of Discount</u>

The EDR discounts shall be funded by SCE's customers on the rate schedules in each portfolio (e.g., customers on the TOU-GS-1 rate will fund the discount for Portfolio 1, customers on the TOU-GS-2 and TOU-GS-3 rates will fund the discount for Portfolio 2, and customers on the TOU-8-SEC, -PRI, -SUB rate schedules will find the discount for Portfolio 3). Discount Revenues and Incremental Load Revenues for each portfolio will

---

[4] Appendix B contains EDR-A, EDR-E and EDR-R tariff schedules and standard agreements, which shall be filed, in substantially the same form, in a Tier 1 advice letter consistent with Paragraph 5 of this Agreement.

be added together to determine the amount of the EDR discount that the schedules within each portfolio shall fund. The Settling Parties recognize that the Commission retains ongoing authority to review SCE's administration of its EDR tariffs.

H. Reporting Requirements

For the life of the program cycle described in Section 4.C., above, SCE will submit to both the Energy Division and the EPCP branch two versions of an annual report every March 1 covering the prior calendar year's EDR activity (and any prorated months depending on when the Commission first approves this Agreement and its subsequent implementation).

1) Confidential Version

One version of the report will be confidential and will contain the following information, arrayed in table format, relative to each EDR participant based on information gathered from the EDR participants:

- Name and location;
- The Standard Industry Code applicable to the participant's business;
- The total amount of the EDR discount provided to the named EDR participant during the reporting period;
- List of jobs retained or created that are attributable to the named EDR participant's involvement in the EDR program[5]; and,
- Wages and benefits attributable during the reporting period to each category of job retained or created by the named EDR participant's involvement in the EDR program, as reported to SCE by the participants.[6]
- The annual maximum kW, the annual kWh, and the rate schedule of each EDR participant.

2) Public Version

The public version of the report shall contain an aggregated analysis of the

[5] Furnishing information to satisfy this requirement shall be optional for Small Customer Accounts after the first time those customers appear in an annual EDR report.

[6] Furnishing information to satisfy this requirement shall be optional for Small Customer Accounts after the first time those customers appear in an annual EDR report.

information contained in the confidential report, as follows:

- Total amount of the annual EDR discounts given during the reporting period;
- Total number of jobs created or retained during the reporting period that are attributable to all participants in the EDR program; and,
- Average salary and benefits attributable during the reporting period to all jobs retained or created by participation in the EDR program.

I. <u>Ratemaking Treatment of Revenues</u>

Revenues received from bundled service customers taking service on the proposed EDR will first be used to pay in full all non-bypassable charges (NBCs). The remaining revenues will be recorded to the Base Revenue Requirement Balancing Account (BRRBA), Energy Resource Recovery Account Balancing Account (ERRA BA), and Portfolio Allocation Balancing Account (PABA) in proportion to what the EDR customer's contribution to these accounts would have been absent the discount. Revenues received from DA or CCA service customers are also first used to pay for all NBCs and CRS charges. To maintain bundled service customers' indifference to the EDR discount, the remaining EDR revenues are allocated to distribution charges only.

5. <u>Limited EDR Program for 2028 Olympics</u>

The parties agree that SCE will offer a limited EDR program for eligible host site customers that are increasing load as a result of 2028 Los Angeles Olympics activities. Certain program features will differ from the standard EDR offered to general EDR customers.
The limited EDR28 will only be available for the period that customer locations are hosting loads associated with the Olympic Games, this includes the setup and teardown periods.

The specific program features are as follows:

- Eligible host sites can be on rate schedules TOU-GS-1 through TOU-8;
- The BPU for participating customers will be based on the average summer load rather than 12-months of load as is the case for general EDR customers.
- Customers will be eligible for the EDR discounts on EDR-E for any incremental load created by activities from the Olympics. The discount would only be applicable

to incremental load and would only apply for the durations of the games (set-up through teardown).

- The incremental load must be at least 150 kW.
- The discount would remain at the current level of 12%.
- Adopt a portfolio approach consisting of three portfolios.
    - Portfolio 1 – Small: TOU-GS-1 rate schedule
    - Portfolio 2 – Small/Medium: TOU-GS-2 and TOU-GS-3 rate schedules
    - Portfolio 3 - Large Power: TOU-8-SEC, -PRI, -SUB rate schedule
- The discount revenues and the incremental load revenues will be allocated to their respective rate groups (i.e., TOU-GS-1 to LSMP; TOU-8-SEC to LP, etc.) such that the net revenue requirements will be applied to each respective rate group.
- The 300 MW general EDR program cap will be retained.
- Small customer participation will be limited to five (5) 2028 Olympic host sites.
- The "But For Affidavit" requirement will be waived.
- Participating customers will not be required to maintain the expansion load for a five-year period.
- Participating customers will not be assessed liquidated damages.

6. <u>Implementation of Settlement Agreement</u>

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement via a Tier 1 advice letter as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement but no sooner than the second quarter of 2026.

7. <u>Incorporation of Complete Agreement</u>

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties.

8. Record Evidence

The Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

9. Signature Date

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

10. Regulatory Approval

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement. The Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties within five business days of the issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

11. Compromise of Disputed Claims

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

12. Non-Precedential

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Settlement Agreement is not precedential in any other pending or future proceeding before this Commission.

The Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in SCE's next GRC Phase 2 proceeding, or earlier if SCE files an application requesting renewal of its EDR program.

13. Previous Communications

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to the subject matter of this Settlement Agreement. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

14. Non-Waiver

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

15. Effect of Subject Headings

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

16. Governing Law

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

17. Number of Originals

This Settlement Agreement may be executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: September 10, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Daniel Hopper
By: Daniel Hopper
Title: Managing Director, Regulatory Affairs

Dated: September 10, 2025

THE UTILITY REFORM NETWORK

/s/ David Cheng
By: David Cheng
Title: Staff Attorney

Dated: September 10, 2025

SMALL BUSINESS UTILITY ADVOCATES

/s/ Britt Marra
By: Britt Marra
Title: Executive Director

Dated: September 10, 2025

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

/s/ Nora Sheriff
By: Nora Sheriff
Title: Attorney

Dated: September 10, 2025

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

/s/ Ronald Liebert
By: Ronald Liebert
Title: Counsel

Dated: September 10, 2025 WALMART INC.

/s/ Julie Clark

By: Julie Clark
Title: Attorney

Appendix A

Comparison of Party Positions on Economic Development Rate Issues and Settlement

Issue	Currently Effective EDR Program	SCE	CLECA	2025 GRC Settled Position
General Program Cap	• 200 MW cap	• 200 MW Program	• No opposition to 200 MW cap, however recommended 300 MW during discussions.	• 300 MW Program
Portfolio Requirements	• N/A	There will be three portfolios as follows: • Portfolio 1 – Small: TOU-GS-1, • Portfolio 2 – Small/Medium: TOU-GS-2 and TOU-GS-3 • Portfolio 3 - Large Power: TOU-8-SEC, -PRI, -SUB	• N/A	Parties agree to three portfolios: • Portfolio 1 – Small: TOU-GS-1, • Portfolio 2 – Small/Medium: TOU-GS-2 and TOU-GS-3 • Portfolio 3 - Large Power: TOU-8-SEC, -PRI, -SUB
Eligibility and other Qualifications	• ≥150 kW non-residential, non-government accounts • Maximum of 20 customers can participate with loads of less than 150 kW • Permit aggregation of smaller accounts to meet 150 kW threshold • Bundled service, DA and CCA service customers Additional safeguards against free-ridership unchanged (liquidated damages, business case review by GO-Biz, etc.)	• Maximum of 60 customers can participate with loads of less than 200 kW • A participation cap of 10 incremental customers will apply to TOU-8-SUB. The total cap over the cycle will be the sum of existing TOU-8-SUB customers and the incremental cap.	• No opposition to current parameters	• Maximum of 60 customers can participate with loads of less than 200 kW • Permit aggregation of smaller accounts to meet 200 kW threshold • Participation cap of 10 incremental customers for TOU-8-SUB. • Bundled service, DA and CCA service customers • Additional safeguards against free-ridership unchanged (liquidated damages, business case review by GO-Biz, etc.) • For new EDR applicants with loads greater than 60 MW, an FTE to load ratio (i.e., FTE/MW) greater than or equal to 1.0 is required.
Discount	12% Standard	20% Standard	25% Standard	20% Standard Discount
"But-For Affidavit"	• Applies to all applicant types *(i.e.*, EDR-R, EDR-A and EDR-E)	• Continue applying to all applicant types.	• No opposition to current treatment	Continue status quo
Contract Term	• 5 years	• 5 years	• 10 years	• 5 years

Issue	Currently Effective EDR Program	SCE	CLECA	2025 GRC Settled Position
	• Additional 12 months to maximum commencement date for EDR-E and EDR-A in the event that SCE requires infrastructure build-out			• Remove the 12 month language and instead allow commencement time to be the date SCE is able to complete installation and energize new power service.
Renewal Eligibility	• No EDR customer can take service on the rate more than once for the same load	• No EDR customer can take service on the rate more than once for the same load		• Continue status quo
Funding of Rate Discount	• Customer-funded	• Customer-funded		• Continue status quo
Reporting	• Annual reports during the EDR program cycle for both Standard and Enhanced EDRs • File annual report with CPUC's EPCP Branch	• Continue status quo		• Continue status quo
Ratemaking Treatment and Revenues	• Revenues for bundled service customers pay NBCs first, then remaining revenues recorded to ERRA and BRRBA in proportion to customers' contribution had they not been billed as EDR customers. For CCA/CA/DA customers, see Paragraph 4.H.	• Revenues received from bundled service customers taking service on the proposed EDR will first be used to pay in full all non-bypassable charges (NBCs). The remaining revenues will be recorded to the Base Revenue Requirement Balancing Account (BRRBA), Energy Resource Recovery Account Balancing Account (ERRA BA), and Portfolio Allocation Balancing Account (PABA) in proportion to what the EDR customer's contribution to these accounts would have been absent the discount.. For CCA/CA/DA customers, see Paragraph 4.I.		• Continue status quo

Appendix B

Economic Development Rate Tariff Schedules

Appendix B-1

SCHEDULE EDR-A

ECONOMIC DEVELOPMENT RATE-ATTRACTION

APPLICABILITY

Applicable to new non-residential, non-governmental customers who locate their facilities at a site within SCE's service territory that results in SCE served load of at least 150 kilowatts (kW) (either individually, or in the aggregate across accounts located at physically and operationally related facility(s)), except for Small Customer Accounts, as defined herein, with loads that are below 150 kW. Such load must be new to California. This Schedule is intended to attract load to California relative to out-of-state options, and is not intended to attract customers from one service area to another within the state, or to attract out-of-state customers to one in-state electric service area or provider over another. Customers will be eligible for service under this Schedule only if the discounts offered under this Schedule were necessary in the customer's decision to locate its new load in California. Additionally, the customer must demonstrate to the satisfaction of SCE that the load subject to this Schedule is new to California. The customer must sign an affidavit attesting to the fact that "but for" this discount, either on its own or in combination with a package of incentives made available to the customer from other sources, the customer would not have located its load in the State of California. This Schedule is not applicable to state and local government customers or residential customers.

EDR discounts are subject to a combined program cap of 300 MW and Small Customer Accounts shall number no more than sixty (60) across all EDR contract types.

TERRITORY

Within the entire territory served.

(Continued)

ECONOMIC DEVELOPMENT RATE-ATTRACTION

RATES

Unless provided herein, or in the Economic Development Rate-Attraction Agreement, all charges and provisions of the customer's Otherwise Applicable Tariff (OAT) shall apply, except that the customer's total bill shall be subject to discount as follows:

20 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.

SPECIAL CONDITIONS

1. Otherwise Applicable Tariff: The customer's regularly filed rate schedule under which service is rendered, including riders.

2. Agreement: The customer must sign the Economic Development Rate-Attraction (EDR-A) Agreement (Form 14-xxx) in order to take service under this Schedule.

3. Small Customer Account: A customer's individual Service Account with load below 201 kW.

4. Start Date: The start date of the discount period shall typically commence within 24 months from the date of execution of the Agreement and Affidavit, unless the delay in commencement of service is due to SCE's need to build infrastructure to serve the EDR-A customer, , in which case, the commencement date shall be the date when SCE is able to complete installation and energize new power service..

5. Participation Cap: A participation cap of 10 incremental customers will apply to TOU-8-SUB. The total cap over the cycle will be the sum of existing TOU-8-SUB customers and the incremental cap.

6. Conservation: In order to be eligible for this Schedule, a customer, with the exception of a Small Customer Account, shall submit all energy efficiency efforts implemented or planned for the future for program eligibility review..

SPECIAL CONDITIONS (Continued)

7. SCE will consult with the California Governor's Office of Business and Economic Development (GO-Biz), or its successor entity, under the supervision of the California Governor's Office Of Business and Economic Development in order to determine qualified customers, with the exception of Small Customer Accounts. Approval by GO-Biz is necessary, but not sufficient, for determining eligibility. SCE reserves the right for final review and eligibility determination, and service under this Schedule shall be offered at the discretion of SCE.

8. All customers must agree to maintain a minimum level of load for five years from the date service is first rendered as set forth in the Economic Development Rate-Attraction Agreement.

9. SCE is under a compliance mandate from the California Public Utilities Commission to provide to the Commission, under seal, (a) a list of the names and locations of its EDR participants, (b) their SIC Codes, (c) the total amount of EDR discount provided to the Customer, (d) a listing of jobs retained or created during the reporting period that are attributable to the named EDR participant's involvement in the EDR program, with the exception of Small Customer Accounts after the first time those customers appear in an annual EDR report; and (e) the amount of the wage and benefits attributable during the reporting period to each category of job retained or created by the named EDR participant's involvement in the EDR program, with the exception of Small Customer Accounts after the first time those customers appear in an annual EDR report. To remain eligible for service under this Schedule, customer must provide SCE with the above-referenced information. SCE shall use reasonable means to protect this data from public disclosure by redacting or aggregating it in any public filings.

10. On the date SCE's tariffs become effective, following a Decision in the 2029 GRC Phase 2 proceeding, or when the EDR 300 MW cap is met, whichever is earlier, this Schedule will be closed to all new Customers applying for the EDR Program. This Schedule will remain open until the expiration of all Customer contracts.

Appendix B-2

SCHEDULE EDR-E

ECONOMIC DEVELOPMENT RATE-EXPANSION

APPLICABILITY

Applicable to existing non-residential, non-governmental customers who increase load by at least 150 kilowatts (kW) over their current Maximum Demand, as established in their EDR-E Agreement, either individually, or in the aggregate across accounts located at physically and operationally related facility(s), except for Small Customer Accounts, as defined herein, with loads that are below 201 kW. Such increase must represent load that is new to California. This Schedule is intended to expand load in California relative to out-of-state options, and is not intended to attract customers from one service area to another within the state, or to attract out-of-state customers to one in-state electric service area or provider over another. Customers who are planning to expand their load at their current site or who are planning to relocate and expand their load at a new site must demonstrate to the satisfaction of SCE that the expanded load subject to this Schedule is new to California. The customer must sign an affidavit attesting to the fact that “but for” this discount, either on its own or in combination with a package of incentives made available to the customer from other sources, the customer would not have expanded its load within the State of California. This Schedule is not applicable to state and local government customers or residential customers.

EDR discounts are subject to a combined program cap of 300 MW and Small Customer Accounts shall number no more than sixty (60) across all EDR contract types.

The customer must establish an average monthly Base Period Usage determined from historical energy and demand (if served on a rate with demand charges). Load eligible for discount under this Schedule is the difference between the monthly metered energy and demand, from the Base Period Usage energy and demand. An existing customer who otherwise qualifies for this option may move all load to a new site in SCE’s territory and still take service under this option for the load that is new to California. To do so, the customer must demonstrate that the operations at the new site are substantially similar to those at the old site, and establish a Base Period Usage at the new site using the load and usage information from the old site.

TERRITORY

Within the entire territory served.

(Continued)

ECONOMIC DEVELOPMENT RATE-EXPANSION

(Continued)

RATES

Unless provided herein, or in the Economic Development Rate-Expansion Agreement, all charges and provisions of the customer's Otherwise Applicable Tariff (OAT) shall apply, except that the customer's total bill shall be subject to discount as follows:

20 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.

SPECIAL CONDITIONS

1. Otherwise Applicable Tariff: The customer's regularly filed rate schedule under which service is rendered, including riders.

2. Agreement: The customer must sign the Economic Development Rate-Expansion (EDR-E) Agreement (Form 14-xxx) in order to take service under this Schedule.

3. Small Customer Account: A customer's individual Service Account with load below 201 kW.

4. Participation Cap: A participation cap of 10 incremental customers will apply to TOU-8-SUB. The total cap over the cycle will be the sum of existing TOU-8-SUB customers and the incremental cap.

5. Start Date: The start date of the discount period shall typically commence within 24 months from the date of execution of the Agreement and Affidavit, unless the delay in commencement of service is due to SCE's need to build infrastructure to serve the EDR-A customer, in which case, the commencement date shall be the date when SCE is able to complete installation and energize new power service..

SPECIAL CONDITIONS (Continued)

6. Metering: Separate electric metering for the customer's Qualifying Incremental Load, as defined in Form 14-XXX, may be required if, in SCE's sole opinion, it is necessary to provide service under this schedule. The customer will be responsible for any costs associated with providing separate electric metering.

7. Conservation: In order to be eligible for this Schedule, a customer, with the exception of a Small Customer Account, shall submit all energy efficiency efforts implemented or planned for the future for program eligibility review. .

8. SCE will consult with the California Governor's Office of Business and Economic Development (GO-Biz), or its successor entity, under the supervision of the Governor's Office Of Business and Economic Development, in order to determine qualified customers, with the exception of a Small Customer Account. Approval by GO-Biz is necessary, but not sufficient, for determining eligibility. SCE reserves the right for final review and eligibility determination, and service under this Schedule shall be offered at the discretion of SCE.

9. All customers must agree to maintain a Minimum Expanded Load, as defined in Form 14-XXX, for five years from the date service is first rendered as set forth in the Economic Development Rate-Expansion Agreement.

10. Base Period Usage: Base Period Usage shall be established and agreed to in the Economic Development Rate-Expansion Agreement. If time-of-use data is not available, the customer's Base Period Usage shall be established using available data, subject to subsequent adjustment based on customer's recorded demand and energy.

11. SCE is under a compliance mandate from the California Public Utilities Commission to provide to the Commission, under seal, (a) a list of the names and locations of its EDR participants, (b) their SIC Codes, (c) the total amount of EDR discount provided to the Customer, (d) a listing of jobs retained or created during the reporting period that are attributable to the named EDR participant's involvement in the EDR program, with the exception of Small Customer Accounts after the first time those customers appear in an annual EDR report; and (e) the amount of the wage and benefits attributable during the reporting period to each category of job retained or created by the named EDR participant's involvement in the EDR program, with the exception of Small Customer Accounts after the first time those customers appear in an annual EDR report. To remain eligible for service under this Schedule, customer must provide SCE with the above-referenced information. SCE shall use reasonable means to protect this data from public disclosure by redacting or aggregating it in any public filings.

12. On the date SCE's tariffs become effective, following a Decision in the 2029 GRC Phase 2 proceeding, or when the EDR 300 MW cap is met, whichever is earlier, this Schedule will be closed to all new Customers applying for the EDR Program. This Schedule will remain open until the expiration of all Customer contracts.

Appendix B-3

SCHEDULE EDR-R

ECONOMIC DEVELOPMENT RATE-RETENTION

APPLICABILITY

Applicable to existing non-residential, non-governmental customers with demands of at least 150 kilowatts (kW), either individually, or in the aggregate across accounts located at physically and operationally related facility(s), except for Small Customer Accounts, as defined herein, with loads that are below 201 kW. The customer must demonstrate to the satisfaction of SCE that relocation of its entire operations or a qualified portion of their operations to a site outside of California is a viable alternative or that closure of the customer's existing facilities, within 12 months, is otherwise imminent. This Schedule is intended to retain load in California relative to out-of-state options, and is not intended to attract customers from one service area to another within the state, or to attract out-of-state customers to one in-state electric service area or provider over another. The customer must sign an affidavit attesting to the fact that "but for" this discount, either on its own or in combination with a package of incentives made available to the customer from other sources, the customer would not have retained load within the State of California. This Schedule is not applicable to state and local government customers or residential customers.

EDR discounts are subject to a combined program cap of 300 MW and Small Customer Accounts shall number no more than sixty (60) across all EDR contract types.

TERRITORY

Within the entire territory served.

RATES

Unless provided herein, or in the Economic Development Rate-Retention Agreement, all charges and provisions of the customer's Otherwise Applicable Tariff (OAT) shall apply, except that the customer's total bill shall be subject to discount as follows:

20 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.

(Continued)

ECONOMIC DEVELOPMENT RATE-RETENTION

(Continued)

SPECIAL CONDITIONS

1. Otherwise Applicable Tariff: The customer's regularly filed rate schedule under which service is rendered, including riders.

2. Agreement: The customer must sign the Economic Development Rate - Retention Agreement (Form xx-xxx) in order to take service under this Schedule.

3. Small Customer Account: A customer's individual Service Account with load below 201 kW.

4. Start Date: The start date of the discount period shall commence within 12 months from the date of execution of the Agreement and shall be designated by the customer within the Agreement.

5. Participation Cap: A participation cap of 10 incremental customers will apply to TOU-8-SUB. The total cap over the cycle will be the sum of existing TOU-8-SUB customers and the incremental cap.

6. Metering: Separate electric metering for a qualified portion of load may be required if, in SCE's sole opinion, it is necessary to provide service under this schedule. The customer will be responsible for any costs associated with providing separate electric metering.

7. Conservation: In order to be eligible for this Schedule, a customer, with the exception of a Small Customer Account, shall submit all energy efficiency efforts implemented or planned for the future for program eligibility review.

SPECIAL CONDITIONS (Continued)

8. SCE will consult with the California Governor's Office of Business and Economic Development (GO-Biz) or its successor entity, under the supervision of the California Governor's Office Of Business and Economic Development, in order to determine qualified customers, with the exception of a Small Commercial Account. Approval by GO-Biz is necessary, but not sufficient, for determining eligibility. SCE reserves the right for final review and eligibility determination, and service under this Schedule shall be offered at the discretion of SCE.

9. All customers must agree to maintain a minimum level of load for five years from the date service is first rendered under this provision as set forth in the EDR-R Agreement.

10. SCE is under a compliance mandate from the California Public Utilities Commission to provide to the Commission, under seal, (a) a list of the names and locations of its EDR participants, (b) their SIC Codes, (c) the total amount of EDR discount provided to the Customer, (d) a listing of jobs retained or created during the reporting period that are attributable to the named EDR participant's involvement in the EDR program, with the exception of Small Customer Accounts after the first time those customers appear in an annual EDR report; and (e) the amount of the wage and benefits attributable during the reporting period to each category of job retained or created by the named EDR participant's involvement in the EDR program, with the exception of Small Customer Accounts after the first time those customers appear in an annual EDR report. To remain eligible for service under this Schedule, customer must provide SCE with the above-referenced information. SCE shall use reasonable means to protect this data from public disclosure by redacting or aggregating it in any public filings.

11. On the date SCE's tariffs become effective, following a Decision in the 2029 GRC Phase 2 proceeding, or when the EDR 300 MW cap is met, whichever is earlier, this Schedule will be closed to all new Customers applying for the EDR Program. This Schedule will remain open until the expiration of all Customer contracts.

Appendix C

ECONOMIC DEVELOPMENT RATE STANDARD AGREEMENTS

Appendix C-1

EDR-A AGREEMENT

ECONOMIC DEVELOPMENT RATE-ATTRACTION AGREEMENT

This Agreement is entered into between ____ ("Customer"),____(Service Account(s)), located at____, and Southern California Edison ("SCE"), located at 2244 Walnut Grove Avenue, Rosemead, California 91770. This Agreement shall become effective as of the date set forth beneath SCE's signature on the signature page of this Agreement. This Economic Development Rate-Attraction Agreement ("Agreement") provides Customer with a discount for electric energy purchased over the five-year term of the Agreement.

Additional applicable Service Accounts and Addresses are: (T)

Service Account	Service Address

This Agreement is a filed form tariff agreement authorized by the California Public Utilities Commission ("Commission") for use by SCE. No officer, inspector, solicitor, agent, or employee of SCE has any authority to waive, alter, or amend any part of this Agreement except as provided herein or as authorized by the Commission. This Agreement is to be used in conjunction with Schedule EDR-A of SCE's Commission-approved tariffs, and supplements the terms and conditions of Customer's electric service under Customer's Otherwise Applicable Tariff, which is Schedule ____ , and all related agreements.

The Parties agree as follows:

1. DEFINITIONS

As used in this Agreement, the following terms shall have the following meanings:

1.1. Added Facilities: Equipment or facilities that are in addition to, or in substitution for, standard facilities that SCE would normally install in order to provide electric service to Customer.

1.2. Agreement: This document and appendices, as amended from time to time.

1.3. Economic Development Rate-Attraction ("EDR-A"): The rates and charges set forth in Schedule EDR-A, subject to the terms and conditions of this Agreement.

1.4. Base Period Usage: As defined in Section 3 of this Agreement.

1.5. Customer: Customer as defined in SCE's Rule 1.

1.6. Forecast Maximum Demand: Customer's forecast of its Total Load maximum demand, including any expansion of load planned over the five years of this Agreement.

1.7. Incremental Added Facilities: Added Facilities that are required by SCE or requested by Customer to be installed in order to accommodate Customer's Load, including any expansion, under Schedule EDR-A.

1.8. Interest Rate: The 90-day commercial paper rate.

1.9. Liquidated Damages: Damages owed by Customer to SCE as provided in Section 10 of this Agreement.

1.10. Minimum Load: The minimum load Customer has agreed to purchase annually as established for Customer in Section 4.

1.11. Otherwise Applicable Tariff (OAT): The rate schedule under which Customer is taking electric service from SCE, including any riders, at the time of signing this Agreement or after, and any applicable successor schedule.

1.12. Party, Parties: The parties to this Agreement are SCE and Customer, as defined above.

1.13. Premises: This term shall mean at physically and operationally related facility(s) . (

C

1.14. North American Industry Classification System ("NAICS") Code: An industry coding system developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about economic activity across North America.

1.15. Small Customer Account: A Customer Account with load below 201 kW.

1.16. Standard Industrial Classification ("SIC") Code: The published codes in the 1987 Standard Industrial Classification Manual issued by the Executive Office of the President, Office of Management and Budget, as may be updated in SCE's discretion.

1.17. Total Load: Customer's recorded (metered) load (energy and demand), as may be aggregated at the same Premises.

1.18. Uncontrollable Force(s): An Uncontrollable Force is an event or occurrence due to influences outside the reasonable control of either or both Parties that could not have been prevented by the exercise of due diligence.

2. ECONOMIC DEVELOPMENT RATE – ATTRACTION

2.1. Customer represents that their NAICS 6-digit Code is ____________ , or theirSIC 3 or 4-digit Code is ____________________.

2.2. Customer further represents that it meets the applicability requirements of Schedule EDR-A.

2.3. Subject to the terms and conditions of this Agreement, SCE will provide 20 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.

2.4. Customer must maintain Total Load demands of at least 150 kW during each of the five years of service under this Agreement, either individually or on an aggregate basis for all accounts at the same Premises. Notwithstanding this provision, Customer can have a lower Total Load demand if the Service Account subject to this Agreement qualifies as a Small Customer Account.

3. BASE PERIOD USAGE

3.1. Base Period Usage must be established for each Customer. For Customers aggregating multiple accounts at a single Premises to meet the Total Load demand provisions specified in Section 2.4, above, BPU is established for the aggregation as a whole and not on an individual Service Account basis.

3.2. SCE shall determine Customer's Base Period Usage by estimating Customer's load characteristics, including estimated demand (provided customer is served on an OAT with demand charges) and energy usage on a time-of-use basis using available data, including Customer's previous electricity bills, if any. That calculation shall be used to determine Customer's Base Period Usage until recorded load data becomes available to more definitively establish Customer load characteristics. When SCE can more accurately estimate Customer's actual load characteristics, Customer's Base Period Usage shall be established based upon the new recorded data.

3.3. If Customer is subject to billing on a time-of-use basis but does not have the requisite historical data to determine its actual base period usage, SCE shall estimate Customer's load characteristics, including estimated demand (provided customer is served on an OAT with demand charges) and energy usage on a time-of-use basis using available data. That calculation shall be used as Customer's Base Period Usage until recorded load data becomes available to more definitively establish Customer's load characteristics. When SCE can more accurately estimate Customer's actual load characteristics, Customer's Base Period Usage shall be established based upon the new recorded data.

	Average Monthly Base Period Usage (kW[7])	Average Hourly Base Period Usage, (kWh)
Facilities Related Demand		N/A
Summer		
On-Peak		
Mid-Peak		
Off-Peak	_______	_______
OVERALL		
Winter		
Mid-Peak		
Off-Peak	_______	_______
OVERALL		

3.4. Base Period Usage is established as follows:

Base Period Usage Facilities Related Demand is computed as follows:

1. Determine a Facilities Related Demand for each month in the period used to establish Base Period Usage that is the greater of:

   a. The maximum billing demand for the month, or

   b. 50% of the highest of all the billing demands in the period used to establish Base Period Usage.

2. Compute the average of the monthly Facilities Related Demands thus determined. This is Base Period Usage Facilities Related Demand.

An "XXX" entered above indicates that the entry is not applicable to Customer's Base Period Usage.

4. MINIMUM LOAD

4.1. Customer must maintain a Minimum Load for each year from the date service is first rendered under Schedule EDR-A for the five-year term of this Agreement.

4.2. The Minimum Load must be at least 150 kW, except for a Small Customer Account. For Customers aggregating multiple accounts at a single Premises to meet the Total Load demand provisions specified in Section 2.4, above, the Minimum Load requirement applies to the aggregation as a whole and not on an individual Service Account basis.

[7] kW BPU may not be applicable for Small Customer Accounts.

4.3. Small Customer Accounts notwithstanding, if during any year of service the Customer's Total Load maximum demand falls below 150 kW in any three months, the Customer's discounts under Section 2.3 above shall be suspended for the balance of the year and such suspension shall begin with the month of the third occurrence. Customer's discounts applicable to Total Load shall resume at the date specified in Section 5.2 of the following year, subject to the terms of this provision. For purposes of this section, a year of service commences with the start of the discount set forth above in Section 2.3. (C

4.4. Any load reductions shown to be directly attributable to energy efficiency measures implemented after establishing Base Period Usage in this Agreement shall not adversely impact the calculation of Customer's Minimum Load. The imputed load reductions attributable to any energy efficiency measure implemented subsequent to the establishment of Base Period Usage shall be added back into the load calculation in the event that Customer's Minimum Load falls below 150 kW. Provided that Customer maintains usage of at least 150 kW (Small Customer Accounts notwithstanding), net of any energy efficiency impacts, all Customer discounts shall apply.

5. COMMENCEMENT OF SERVICE

5.1. SCE will begin providing the Customer service under Schedule EDR-A at the start of the next regular billing period following the date the Customer notifies SCE that service should begin under Schedule EDR-A, which date shall typically not be more than 24 months from the effective date of this Agreement unless the delay in commencement of service is due to SCE's need to build adequate infrastructure, in which case, the commencement date shall be the date when SCE is able to complete installation and energize new power service.

5.2. Customer estimates that service under Schedule EDR-A shall commence at the start of the next regular billing period beginning after __________________ and shall provide SCE at least five business days' notice of any change in such date.

6. ADDED FACILITIES

An Added Facilities Contract, Form 16-308 or 16-309, shall be required if additional equipment or facilities are required for Added Facilities or Incremental Added Facilities.

7. ACKNOWLEDGMENT

7.1. Except as otherwise amended herein, Customer acknowledges that it is fully subject to all terms and conditions contained in Customer's OAT, or its successor rate schedule, all of SCE's rules, and all terms and conditions of service contained in SCE's Commission-approved tariffs. Any provision pertaining to either a peak period rate limiter or an average rate limiter does not apply.

7.2. Customer also acknowledges that SCE is under a compliance mandate from the California Public Utilities Commission to provide to the Commission, under seal, (a) a list of the names and locations of its EDR participants, (b) their SIC Codes, (c) the total EDR discount provided to the Customer, (d) a listing of jobs retained or created during the relevant period that are attributable to the named EDR participant's involvement in the EDR program; and (e) the amount of the wage and benefits attributable during the relevant period to each category of job retained or created by the named EDR participant's involvement in the EDR program. Customer acknowledges that it is to provide to SCE **by no later than January 31 of each reportable year** any of the information above upon request in order to remain eligible to take service pursuant to this Agreement. Failure to timely furnish this information could lead, in SCE's sole discretion, to revocation of this Agreement. SCE shall use reasonable means to protect this data from public disclosure by redacting or aggregating it in any public filings.

8. TERM

8.1. This Agreement shall be effective for five years following the commencement of service under Schedule EDR-A pursuant to Section 5 of this Agreement.

8.2. At the end of the fifth year, Customer will no longer take service under Schedule EDR-A and will be billed only under its OAT, effective with the start of the next regular billing period following the end of the fifth year of service under this Agreement.

8.3. This Agreement is not renewable at the expiration of its term, nor can the beneficiary of this Agreement take service on an EDR rate again for the same load served under this Agreement.

8.4. This Agreement must be executed prior to the date on which SCE's tariffs implementing the 2029 GRC Phase 2 become effective or when the EDR 300 MW cap from the latest Decision is met, whichever is earlier. (N)

9. TERMINATION

This Agreement may be terminated (subject to payment of Liquidated Damages as provided for in Section 10) by either party upon written notice as follows.

9.1. Termination for Misrepresentation or Fraud: SCE may terminate this Agreement upon five business days' notice if any representation made by Customer in this Agreement is untrue in any material respect, or if any statement in Customer's Affidavit was untrue, or if SCE determines that Customer was not eligible for Schedule EDR-A when this Agreement was signed, in which case Liquidated Damages as set forth in Section 10.3 shall be paid.

9.2. Termination at Customer's Request: Customer may request termination of this Agreement at any time by providing at least 60 days' written notice to SCE.

9.3. Termination For Nonpayment: SCE may terminate this Agreement if Customer fails to pay any amount due, under Schedule EDR-A within 30 days after receipt of notice of nonpayment from SCE. Customer shall be liable for all unpaid amounts and any accrued interest on the unpaid amounts.

9.4. Termination For Noncompliance: SCE may terminate this Agreement upon five business days' notice if Customer fails to comply with any term or condition of Schedule EDR-A or this Agreement.

9.5. Termination For Ineligibility: SCE may terminate this Agreement upon five business days' notice if it determines that Customer has become ineligible for Schedule EDR-A.

9.6. Termination For Failure To Maintain Minimum Load: SCE may terminate this Agreement if Customer fails to maintain its Minimum Load during any consecutive 12 month period or shuts down its operations. If Customer fails to maintain its Minimum Load, SCE must provide Customer at least 90 days' notice of termination and Customer shall have the opportunity to increase its load to the Minimum Load and demonstrate to SCE's satisfaction that it will continue to use its Minimum Load for the remaining term of this Agreement.

9.7. Termination For Failure To Commence Service: SCE may terminate this Agreement if Customer does not begin service as required in Section 5 of this Agreement.

9.8 Termination for Ceasing Operations: SCE may terminate this Agreement upon five business days' notice if Customer ceases the operations to which this Agreement applies or moves such operations out of SCE's service territory.

10. LIQUIDATED DAMAGES

10.1 Upon termination of this Agreement, prior to its five-year term pursuant to Sections 9.1, 9.2, 9.3, 9.4, 9.5, or 9.6, Customer shall be required to pay SCE Liquidated Damages. The Liquidated Damages are required to ensure that neither SCE nor its ratepayers are financially or otherwise damaged if this Agreement is prematurely terminated before the end of its term. (Excludes business closure, relocation, or reduction in load without relocation) (

10.2. It would be extremely difficult for the Parties to identify the amounts of increased or additional costs attributable to termination of this Agreement. Parties agree the Liquidated Damages specified herein are a reasonable approximation of damages which SCE and its ratepayers may incur as a result of such termination, and that the damage amount does not represent a penalty.

10.3. For termination under Section 9.1 above, Liquidated Damages under this Agreement shall be an amount equal to 200 percent of the cumulative difference between (i) the amount the Customer would have paid for its energy and demand if billed at their OAT from the date service was first rendered under Schedule EDR-A to the date of termination, and (ii) the amount billed to Customer under this Agreement and Schedule EDR-A during the same period.

10.4. For termination under Sections 9.2, 9.3, 9.4, 9.5, or 9.6 above, Liquidated Damages under this Agreement shall be an amount equal to 100 percent of the cumulative difference between (i) the amount billed to Customer under Schedule EDR-A from the date service was first rendered under Schedule EDR-A to the date of termination, and (ii) a "proxy" bill calculation based on a declining discount starting at 20 percent of the customer's OAT bill in year one with that annual discount reduced by 4 percent each year thereafter during the same period, *i.e.,* a discount of 16 percent in year 2, 12 percent in year 3, 8 percent in year 4, and 4 percent in year 5, plus interest on that difference (at the Interest Rate) to the date of payment. Should a customer's usage increase such that cumulative liquidated damages become negative upon contract termination, under no circumstances will SCE be liable for paying liquidated damages to a customer.

10.5. After termination of this Agreement for any cause, Customer shall be billed at its OAT.

10.6. The limitations of Rule 17 of SCE's Commission-approved Tariffs shall not apply to amounts payable under this Agreement.

10.7. SCE may in its discretion require Customer to establish a letter of credit or other security as a condition to providing service under Schedule EDR-A to secure payment of any Liquidated Damages.

11. UNCONTROLLABLE FORCE

11.1. Neither Party shall be considered to be in default in the performance of any obligation under this Agreement, except for obligations to pay money, when and to the extent that failure of performance shall be caused by an Uncontrollable Force.

11.2. If either Party, because of an Uncontrollable Force, is rendered wholly or partly unable to perform its obligations under this Agreement, the Party shall be excused from whatever performance is affected by the Uncontrollable Force to the extent the following conditions are met.

11.2.1 The suspension of performance is of no greater scope and of no longer duration than is required by the Uncontrollable Force.

11.2.2. The nonperforming Party uses its best efforts to cure its inability to perform. This subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty.

11.2.3. When the nonperforming Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect immediately.

11.3. Nonperformance due to Uncontrollable Force shall be excused, provided Party can demonstrate that the Uncontrollable Force was owing to causes outside its reasonable control and the occurrence of the Uncontrollable Force could not have been prevented by the exercise of due diligence.

11.3.1. Accordingly, nonperformance shall be excused from the date of the occurrence of the Uncontrollable Force, provided the nonperforming Party has given the other Party written notice describing the particulars of the occurrence within two weeks of the event.

11.3.2. Accordingly, nonperformance shall be excused from the date on which the nonperforming Party gives the other Party written notice describing the particulars of the occurrence of the Uncontrollable Force, if such written notice is given more than two weeks after the Uncontrollable Force occurred.

11.4. If Customer experiences an Uncontrollable Force that prevents Customer from complying with Schedule EDR-A and this Agreement, Customer may request that SCE suspend the terms of Schedule EDR-A and this Agreement for the duration of the Uncontrollable Force. Customer will be billed at the Otherwise Applicable Tariff for the duration of the suspension of this Agreement. Resumption of the terms of Schedule EDR-A and this Agreement shall commence with the next regularly scheduled billing period. In addition, the term of this Agreement will be extended for up to 12 months beyond the term originally established in this Agreement by the length of time this Agreement was suspended.

11.5. The occurrence of an Uncontrollable Force shall not (i) prevent SCE from terminating this Agreement in accordance with Sections 9.4 and 9.5, or (ii) extend the period any level of discount is available as provided in Section 2.3.

11.6. If the Uncontrollable Force causing the nonperformance is caused by the actions or inactions of legislative, judicial or regulatory agencies, or other proper authority, this Agreement may be amended to comply with the legal or regulatory change causing the nonperformance. Any such amendment must be first authorized by the Commission prior to implementation.

12. DAMAGE LIMITATION

SCE shall not be liable for any consequential, incidental, indirect, or special damages, whether in contract, tort, or strict liability including, but not limited to, lost profits and loss of power resulting from power outages or other electric service interruptions or from SCE’s performance or nonperformance of its obligations under this Agreement or in the event of termination of this Agreement.

13. INDEMNITY

Customer shall, at its own cost and expense, defend, indemnify, and hold harmless SCE, its officers, agents, employees, assigns, and successors in interest, from and against any and all liability, damages, losses, claims, demands, actions, cause of action, costs, including attorney's fees and expenses, or any of them, resulting from the death or injury to any person or damage to any property caused by Customer, its employees, officers and agents, or any of them, and arising out of the performance or non-performance of its obligations under this Agreement. Termination of this Agreement shall not exempt Customer from the terms and conditions of this Section.

14. ASSIGNMENT OF AGREEMENT

Customer shall not assign this Agreement or any part or interest thereof, to a third party without the prior, written consent of an authorized representative of SCE. Any assignment made without such consent shall be void and of no effect. Further, any assignment made under this Agreement shall be subject to any applicable Commission authorization or regulation except as waived by the Commission.

15. AMENDMENT

Any changes or amendments to this Agreement must be in writing and must be executed by the Customer and SCE and, if required, be approved by the Commission.

16. NOTICE

Any notice either Customer or SCE may wish to provide the other regarding this Agreement must be in writing and may be transmitted by hand, fax, email or postal mail. Notices delivered by hand shall be deemed effective when delivered. Notices delivered by fax, email and mail shall be deemed effective when received.

Customer: ______________________________

(name) ______________________________

(title) ______________________________

(party) ______________________________

(address ______________________________

(city, state, & zip code)

SCE: Manager, Economic Development Services
Southern California Edison Company
6070-F No. Irwindale Avenue
Irwindale, CA 91702

17. NONWAIVER

The failure of either Party to enforce any of the terms and conditions or to exercise any right or privilege in this Agreement shall not be construed as a waiver of any such terms and conditions or rights or privileges, and the same shall continue and remain in force and effect as if no such failure to enforce or exercise had occurred.

18. SEVERABILITY

In the event that any of the provisions, or portions thereof, of this Agreement are held to be unenforceable or invalid by the Commission, or any court of competent jurisdiction, the validity and enforceability of the remaining provisions or any portion thereof shall not be affected. However, should either party determine, in good faith, that such unenforceability renders the remaining provisions of this Agreement economically infeasible or disadvantageous, said party may terminate this Agreement upon 15 days' notice, except that the provisions of Section 10, Liquidated Damages, shall apply to any such termination.

19. APPLICABLE LAWS, RULES, AND REGULATIONS

This Agreement shall be subject to, and interpreted under, the laws, rules, and regulations of the State of California and the Commission, and under SCE's Commission-approved Tariff Schedules and Rules. To the extent there are any inconsistencies between this Agreement and SCE's other tariffs, this Agreement shall control.

20. CALIFORNIA PUBLIC UTILITIES COMMISSION

20.1. This Agreement shall at all times be subject to such changes or modifications by the Commission as said Commission may, from time to time, direct in the exercise of its jurisdiction.

20.2. Notwithstanding any other provisions of this Agreement, SCE has the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in rates, charges, classification, service, or rule, or any agreement relating thereto.

20.3 This Agreement shall be subject to review in any proceeding the Commission may conduct regarding SCE's EDR program implementation.

21. ENTIRE AGREEMENT

This Agreement, including SCE's tariffs as filed with the Public Utilities Commission, constitutes the sole, only, and entire agreement and understanding between the Parties as to the subject matter of this Agreement with respect to Schedule EDR-A. Prior agreements, commitments or representations, whether expressed or implied, and discussions between Parties, shall not be construed to be a part of this Agreement.

22. AUTHORIZATION SIGNATURES

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized agents to be effective on the date of SCE's signature below.

By: SOUTHERN CALIFORNIA EDISON COMPANY	By: CUSTOMER
____________________	____________________
(Signature)	(Signature)
____________________	____________________
(Name)	(Name)
____________________	____________________
(Title)	(Title)
Southern California Edison Company	
____________________	____________________
	(Customer)
____________________	____________________
(Date)	(Date)

AFFIDAVIT FOR ECONOMIC DEVELOPMENT ATTRACTION RATES

By signing this affidavit, an Applicant who attracts load to the service territory of Southern California Edison (SCE) hereby certifies and declares under penalty of perjury under the laws of the State of California that the statements in the following paragraphs are true and correct:

1. But for the receipt of the applicable discounted EDR and the terms of the corresponding EDR-A Agreement, either on its own or in combination with an economic development incentive package, the Applicant's load would not be attracted to California.

2. Applicant has discussed with SCE the cost-effective conservation and load management measures the Applicant may take to reduce their electric bills and the load they place on SCE's system.

3. Customer confirms that its NAICS Code(s) and SIC Code(s) are as stated in the applicable EDR-A Agreement and that it is eligible for the applicable EDR-A schedule.

4. Customer certifies that all load subject to the applicable EDR-A Agreement represents load that is eligible for the applicable EDR-A schedule. (

Executed this ________day of ________________, ________.

By: APPLICANT ________________________________

Signature: ________________________________

Name: ________________________________

Title: ________________________________

Appendix C-2

EDR-E AGREEMENT

ECONOMIC DEVELOPMENT RATE-EXPANSION AGREEMENT
(Post Decision xxx)

This Agreement is entered into between ____ ("Customer"),____(Service Account(s)), located at____, and Southern California Edison ("SCE"), located at 2244 Walnut Grove Avenue, Rosemead, California 91770. This Agreement shall become effective as of the date set forth beneath SCE's signature on the signature page of this Agreement. This Economic Development Rate-Expansion Agreement ("Agreement") provides Customer with a discount for electric energy purchased over the five-year term of the Agreement.

Additional applicable Service Accounts and Addresses are: (T)

Service Account	Service Address

This Agreement is a filed form tariff agreement authorized by the California Public Utilities Commission ("Commission") for use by SCE. No officer, inspector, solicitor, agent, or employee of SCE has any authority to waive, alter, or amend any part of this Agreement except as provided herein or as authorized by the Commission. This Agreement is to be used in conjunction with Schedule EDR-E of SCE's Commission-approved tariffs, and supplements the terms and conditions of Customer's electric service under Customer's Otherwise Applicable Tariff, which is Schedule ____ , and all related agreements.

The Parties agree as follows:

1. DEFINITIONS

As used in this Agreement, the following terms shall have the following meanings:

1.1. Added Facilities: Equipment or facilities that are in addition to, or in substitution for, standard facilities that SCE would normally install in order to provide electric service to Customer.

1.2. Agreement: This document and appendices, as amended from time to time.

1.3. Economic Development Rate-Expansion ("EDR-E"): The rates and charges set forth in Schedule EDR-E, subject to the terms and conditions of this Agreement.

1.4. Base Period Usage: As defined in Section 3 of this Agreement.

1.5. Customer: Customer as defined in SCE's Rule 1.

1.6. Forecast Maximum Demand: Customer's forecast of its Total Load maximum demand, including any expansion of load planned over the five years of this Agreement.

1.7. Incremental Added Facilities: Added Facilities that are required by SCE or requested by Customer to be installed in order to accommodate Customer's Load, including any expansion, under Schedule EDR-E.

1.8. Interest Rate: The 90-day commercial paper rate.

1.9. Liquidated Damages: Damages owed by Customer to SCE as provided in Section 10 of this Agreement.

1.10. Minimum Load: The minimum load Customer has agreed to purchase annually as established for Customer in Section 4.

1.11. Otherwise Applicable Tariff (OAT): The rate schedule under which Customer is taking electric service from SCE, including any riders, at the time of signing this Agreement or after, and any applicable successor schedule.

1.12. Party, Parties: The parties to this Agreement are SCE and Customer, as defined above.

1.13. Premises: This term shall mean at the physically and operationally related facility(s).

1.14. North American Industry Classification System ("NAICS") Code: An industry coding system developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about economic activity across North America.

1.15. Small Customer Account: A Customer Account with load below 201 kW that is not subject to the 150 kW eligibility requirement.

1.16. Standard Industrial Classification ("SIC") Code: The published codes in the 1987 Standard Industrial Classification Manual issued by the Executive Office of the President, Office of Management and Budget, as may be updated in SCE's discretion.

1.17. Total Load: Customer's recorded (metered) load (energy and demand), as may be aggregated at the same Premises.

1.18. Uncontrollable Force(s): An Uncontrollable Force is an event or occurrence due to influences outside the reasonable control of either or both Parties that could not have been prevented by the exercise of due diligence.

2. ECONOMIC DEVELOPMENT RATE – EXPANSION

2.1. Customer represents that their NAICS 4-digit Code is ________________ , or their SIC 3 or 4-digit Code is ____________________ .

2.2. Customer further represents that it meets the applicability requirements of

Schedule EDR-E.

2.3. Subject to the terms and conditions of this Agreement, SCE will provide 20 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.

2.4. Customer must maintain Total Incremental Load demands of at least 150 kW during each of the five years of service under this Agreement, either individually or on aggregate basis for all accounts at the same Premises. Notwithstanding this provision, Customer can have a lower Total Incremental Load demand if the Service Account subject to this Agreement qualifies as a Small Customer Account.

3. BASE PERIOD USAGE

3.1. Base Period Usage must be established for each Customer to determine Incremental Load. For Customers aggregating multiple accounts at a single Premises to meet the Total Incremental Load demand provisions specified in Section 2.4, above, BPU is established for the aggregation as a whole and not on an individual Service Account basis.

3.2. SCE shall determine Customer's Base Period Usage by estimating Customer's load characteristics, including estimated demand (provided customer is served on an OAT with demand charges) and energy usage on a time-of-use basis using available data, including Customer's previous electricity bills, if any. That calculation shall be used to determine Customer's Base Period Usage until recorded load data becomes available to more definitively establish Customer load characteristics. When SCE can more accurately estimate Customer's actual load characteristics, Customer's Base Period Usage shall be established based upon the new recorded data.

3.3. If Customer is subject to billing on a time-of-use basis but does not have the requisite historical data to determine its actual base period usage, SCE shall estimate Customer's load characteristics, including estimated demand (provided customer is served on an OAT with demand charges) and energy usage on a time-of-use basis using available data. That calculation shall be used as Customer's Base Period Usage until recorded load data becomes available to more definitively establish Customer's load characteristics. When SCE can more accurately estimate Customer's actual load characteristics, Customer's Base Period Usage shall be established based upon the new recorded data.

3.4. Base Period Usage is established as follows:

	Average Monthly Base Period Usage (kW[8])	Average Hourly Base Period Usage, (kWh)
Facilities Related Demand		N/A
Summer		
On-Peak		
Mid-Peak		
Off-Peak		
OVERALL		
Winter		
Mid-Peak		
Off-Peak		
Super Off-Peak		
OVERALL		

Base Period Usage Facilities Related Demand is computed as follows:

1. Determine a Facilities Related Demand for each month in the period used to establish Base Period Usage that is the greater of:

   a. The maximum billing demand for the month, or

   b. 50% of the highest of all the billing demands in the period used to establish Base Period Usage.

2. Compute the average of the monthly Facilities Related Demands thus determined. This is Base Period Usage Facilities Related Demand.

An "XXX" entered above indicates that the entry is not applicable to Customer's Base Period Usage.

4. MINIMUM EXPANDED LOAD

4.1. Customer must maintain a Minimum Expanded Load for each year from the date service is first rendered under Schedule EDR-E for the five-year term of this Agreement.

4.2. The Minimum Expanded Load must be at least 150 kW, except for a Small Customer Account. For Customers aggregating multiple accounts at a single Premises to meet the Total Expanded Load demand provisions specified in Section 2.4, above, the Minimum Load requirement applies to the aggregation as a whole and not on an individual Service Account basis.

[8] kW BPU may not be applicable for Small Customer Accounts.

4.3. Small Customer Accounts notwithstanding, if during any year of service the Customer's Total Expanded Load maximum demand falls below 150 kW in any three months, the Customer's discounts under Section 2.3 above shall be suspended for the balance of the year and such suspension shall begin with the month of the third occurrence. Customer's discounts applicable to Total Expanded Load shall resume at the date specified in Section 5.2 of the following year, subject to the terms of this provision. For purposes of this section, a year of service commences with the start of each level of discount set forth above in Section 2.3. (C)

4.4. Any load reductions shown to be directly attributable to energy efficiency measures implemented after establishing Base Period Usage in this Agreement shall not adversely impact the calculation of Customer's Minimum Expanded Load. The imputed load reductions attributable to any energy efficiency measure implemented subsequent to the establishment of Base Period Usage shall be added back into the load calculation in the event that Customer's Minimum Expanded Load falls below 150 kW. Provided that Customer maintains usage of at least 150 kW (Small Customer Accounts notwithstanding), net of any energy efficiency impacts, all Customer discounts shall apply.

5. COMMENCEMENT OF SERVICE

5.1. SCE will begin providing the Customer service under Schedule EDR-E at the start of the next regular billing period following the date the Customer notifies SCE that service should begin under Schedule EDR-E, which date shall typically not be more than 24 months from the effective date of this Agreement unless the delay in commencement of service is due to SCE's need to build adequate infrastructure, in which case, the commencement date shall be the date when SCE is able to complete installation and energize new power service.

5.2. Customer estimates that service under Schedule EDR-E shall commence at the start of the next regular billing period beginning after __________________ and shall provide SCE at least five business days' notice of any change in such date.

6. ADDED FACILITIES

An Added Facilities Contract, Form 16-308 or 16-309, shall be required if additional equipment or facilities are required for Added Facilities or Incremental Added Facilities.

7. ACKNOWLEDGMENT

7.1. Except as otherwise amended herein, Customer acknowledges that it is fully subject to all terms and conditions contained in Customer's OAT, or its successor rate schedule, all of SCE's rules, and all terms and conditions of service contained in SCE's Commission-approved tariffs. Any provision pertaining to either a peak period rate limiter or an average rate limiter does not apply.

7.2. Customer also acknowledges that SCE is under a compliance mandate from the California Public Utilities Commission to provide to the Commission, under seal, (a) a list of the names and locations of its EDR participants, (b) their SIC Codes, (c) the total EDR discount provided to the Customer, (d) a listing of jobs retained or created during the relevant period that are attributable to the named EDR participant's involvement in the EDR program; and (e) the amount of the wage and benefits attributable during the relevant period to each category of job retained or created by the named EDR participant's involvement in the EDR program.

Customer acknowledges that it is to provide to SCE **by no later than January 31 of each reportable year** any of the information above upon request in order to remain eligible to take service pursuant to this Agreement. Failure to timely furnish this information could lead, in SCE's sole discretion, to revocation of this Agreement. SCE shall use reasonable means to protect this data from public disclosure by redacting or aggregating it in any public filings.

8. TERM

8.1. This Agreement shall be effective for five years following the commencement of service under Schedule EDR-E pursuant to Section 5 of this Agreement.

8.2. At the end of the fifth year, Customer will no longer take service under Schedule EDR-E and will be billed only under its OAT, effective with the start of the next regular billing period following the end of the fifth year of service under this Agreement.

8.3. This Agreement is not renewable at the expiration of its term, nor can the beneficiary of this Agreement take service on an EDR rate again for the same load served under this Agreement.

8.4. This Agreement must be executed prior to the date on which SCE's tariffs implementing the 2029 GRC Phase 2 become effective or when the EDR 300 MW cap from the latest Decision is met, whichever is earlier.

9. TERMINATION

This Agreement may be terminated (subject to payment of Liquidated Damages as provided for in Section 10) by either party upon written notice as follows.

9.1. <u>Termination for Misrepresentation or Fraud:</u> SCE may terminate this Agreement upon five business days' notice if any representation made by Customer in this Agreement is untrue in any material respect, or if any statement in Customer's Affidavit was untrue, or if SCE determines that Customer was not eligible for Schedule EDR-E when this Agreement was signed, in which case Liquidated Damages as set forth in Section 10.3 shall be paid.

9.2. <u>Termination at Customer's Request:</u> Customer may request termination of this Agreement at any time by providing at least 60 days' written notice to SCE.

9.3. <u>Termination For Nonpayment:</u> SCE may terminate this Agreement if Customer fails to pay any amount due, under Schedule EDR-E within 30 days after receipt of notice of nonpayment from SCE. Customer shall be liable for all unpaid amounts and any accrued interest on the unpaid amounts.

9.4. <u>Termination For Noncompliance:</u> SCE may terminate this Agreement upon five business days' notice if Customer fails to comply with any term or condition of Schedule EDR-E or this Agreement.

9.5. <u>Termination For Ineligibility:</u> SCE may terminate this Agreement upon five business days' notice if it determines that Customer has become ineligible for Schedule EDR-E.

9.6. <u>Termination For Failure To Maintain Minimum Load:</u> SCE may terminate this Agreement if Customer fails to maintain its Minimum Load during any consecutive 12 month period or shuts down its operations. If Customer fails to maintain its Minimum Expanded Load, SCE must provide Customer at least 90 days' notice of termination and Customer shall have the opportunity to increase its load to the Minimum Expanded Load and demonstrate to SCE's satisfaction that it will continue to use its Minimum Expanded Load for the remaining term of this Agreement.

9.7. Termination For Failure To Commence Service: SCE may terminate this Agreement if Customer does not begin service as required in Section 5 of this Agreement.

9.8 Termination for Ceasing Operations: SCE may terminate this Agreement upon five business days' notice if Customer ceases the operations to which this Agreement applies or moves such operations out of SCE's service territory.

10. LIQUIDATED DAMAGES

10.1 Upon termination of this Agreement, prior to its five-year term pursuant to Sections 9.1, 9.2, 9.3, 9.4, 9.5, or 9.6, Customer shall be required to pay SCE Liquidated Damages. The Liquidated Damages are required to ensure that neither SCE nor its ratepayers are financially or otherwise damaged if this Agreement is prematurely terminated before the end of its term. (Excludes business closure, relocation, or reduction in load without relocation) (
D

10.2. It would be extremely difficult for the Parties to identify the amounts of increased or additional costs attributable to termination of this Agreement. Parties agree the Liquidated Damages specified herein are a reasonable approximation of damages which SCE and its ratepayers may incur as a result of such termination, and that the damage amount does not represent a penalty.

10.3. For termination under Section 9.1 above, Liquidated Damages under this Agreement shall be an amount equal to 200 percent of the cumulative difference between (i) the amount the Customer would have paid for its energy and demand if billed at their OAT from the date service was first rendered under Schedule EDR-E to the date of termination, and (ii) the amount billed to Customer under this Agreement and Schedule EDR-E during the same period.

10.4. For termination under Sections 9.2, 9.3, 9.4, 9.5, or 9.6 above Liquidated Damages under this Agreement shall be an amount equal to 100 percent of the cumulative difference between (i) the amount billed to Customer under Schedule EDR-E from the date service was first rendered under Schedule EDR-E to the date of termination, and (ii) a "proxy" bill calculation based on a declining discount starting at 20 percent of the customer's OAT bill in year one with that annual discount reduced by 4 percent each year thereafter during the same period, i.e., a discount of 16 percent in year 2, 12 percent in year 3, 8 percent in year 4, and 4 percent in year 5, plus interest on that difference (at the Interest Rate) to the date of payment. Should a customer's usage increase such that cumulative liquidated damages become negative upon contract termination, under no circumstances will SCE be liable for paying liquidated damages to a customer.

10.5. After termination of this Agreement for any cause, Customer shall be billed at its OAT.

10.6. The limitations of Rule 17 of SCE's Commission-approved Tariffs shall not apply to amounts payable under this Agreement.

10.7. SCE may in its discretion require Customer to establish a letter of credit or other security as a condition to providing service under Schedule EDR-E to secure payment of any Liquidated Damages.

11. UNCONTROLLABLE FORCE

11.1. Neither Party shall be considered to be in default in the performance of any obligation under this Agreement, except for obligations to pay money, when and to the extent that failure of performance shall be caused by an Uncontrollable Force.

11.2. If either Party, because of an Uncontrollable Force, is rendered wholly or partly unable to perform its obligations under this Agreement, the Party shall be excused from whatever performance is affected by the Uncontrollable Force to the extent the following conditions are met.

11.2.1 The suspension of performance is of no greater scope and of no longer duration than is required by the Uncontrollable Force.

11.2.2. The nonperforming Party uses its best efforts to cure its inability to perform. This subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty.

11.2.3. When the nonperforming Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect immediately.

11.3. Nonperformance due to Uncontrollable Force shall be excused, provided Party can demonstrate that the Uncontrollable Force was owing to causes outside its reasonable control and the occurrence of the Uncontrollable Force could not have been prevented by the exercise of due diligence.

11.3.1. Accordingly, nonperformance shall be excused from the date of the occurrence of the Uncontrollable Force, provided the nonperforming Party has given the other Party written notice describing the particulars of the occurrence within two weeks of the event.

11.3.2. Accordingly, nonperformance shall be excused from the date on which the nonperforming Party gives the other Party written notice describing the particulars of the occurrence of the Uncontrollable Force, if such written notice is given more than two weeks after the Uncontrollable Force occurred.

11.4. If Customer experiences an Uncontrollable Force that prevents Customer from complying with Schedule EDR-E and this Agreement, Customer may request that SCE suspend the terms of Schedule EDR-E and this Agreement for the duration of the Uncontrollable Force. Customer will be billed at the Otherwise Applicable Tariff for the duration of the suspension of this Agreement. Resumption of the terms of Schedule EDR-E and this Agreement shall commence with the next regularly scheduled billing period. In addition, the term of this Agreement will be extended for up to 12 months beyond the term originally established in this Agreement by the length of time this Agreement was suspended.

11.5. The occurrence of an Uncontrollable Force shall not (i) prevent SCE from terminating this Agreement in accordance with Sections 9.4 and 9.5, or (ii) extend the period any level of discount is available as provided in Section 2.3.

11.6. If the Uncontrollable Force causing the nonperformance is caused by the actions or inactions of legislative, judicial or regulatory agencies, or other proper authority, this Agreement may be amended to comply with the legal or regulatory change causing the nonperformance. Any such amendment must be first authorized by the Commission prior to implementation.

12. DAMAGE LIMITATION

SCE shall not be liable for any consequential, incidental, indirect, or special damages, whether in contract, tort, or strict liability including, but not limited to, lost profits and loss of power resulting from power outages or other electric service interruptions or from SCE's performance or nonperformance of its obligations under this Agreement or in the event of termination of this Agreement.

13. INDEMNITY

Customer shall, at its own cost and expense, defend, indemnify, and hold harmless SCE, its officers, agents, employees, assigns, and successors in interest, from and against any and all liability, damages, losses, claims, demands, actions, cause of action, costs, including attorney's fees and expenses, or any of them, resulting from the death or injury to any person or damage to any property caused by Customer, its employees, officers and agents, or any of them, and arising out of the performance or non-performance of its obligations under this Agreement. Termination of this Agreement shall not exempt Customer from the terms and conditions of this Section.

14. ASSIGNMENT OF AGREEMENT

Customer shall not assign this Agreement or any part or interest thereof, to a third party without the prior, written consent of an authorized representative of SCE. Any assignment made without such consent shall be void and of no effect. Further, any assignment made under this Agreement shall be subject to any applicable Commission authorization or regulation except as waived by the Commission.

15. AMENDMENT

Any changes or amendments to this Agreement must be in writing and must be executed by the Customer and SCE and, if required, be approved by the Commission.

16. NOTICE

Any notice either Customer or SCE may wish to provide the other regarding this Agreement must be in writing and may be transmitted by hand, fax, email or postal mail. Notices delivered by hand shall be deemed effective when delivered. Notices delivered by fax, email and mail shall be deemed effective when received.

Customer:

____
(name)
____
(title)
____
(party)
____
(address)
____
(city, state, & zip code)

SCE: Manager, Economic Development Services
Southern California Edison Company
6070-F No. Irwindale Avenue
Irwindale, CA 91702

17. NONWAIVER

The failure of either Party to enforce any of the terms and conditions or to exercise any right or privilege in this Agreement shall not be construed as a waiver of any such terms and conditions or rights or privileges, and the same shall continue and remain in force and effect as if no such failure to enforce or exercise had occurred.

18. SEVERABILITY

In the event that any of the provisions, or portions thereof, of this Agreement are held to be unenforceable or invalid by the Commission, or any court of competent jurisdiction, the validity and enforceability of the remaining provisions or any portion thereof shall not be affected. However, should either party determine, in good faith, that such unenforceability renders the remaining provisions of this Agreement economically infeasible or disadvantageous, said party may terminate this Agreement upon 15 days' notice, except that the provisions of Section 10, Liquidated Damages, shall apply to any such termination.

19. APPLICABLE LAWS, RULES, AND REGULATIONS

This Agreement shall be subject to, and interpreted under, the laws, rules, and regulations of the State of California and the Commission, and under SCE's Commission-approved Tariff Schedules and Rules. To the extent there are any inconsistencies between this Agreement and SCE's other tariffs, this Agreement shall control.

20. CALIFORNIA PUBLIC UTILITIES COMMISSION

20.1. This Agreement shall at all times be subject to such changes or modifications by the Commission as said Commission may, from time to time, direct in the exercise of its jurisdiction.

20.2. Notwithstanding any other provisions of this Agreement, SCE has the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in rates, charges, classification, service, or rule, or any agreement relating thereto.

20.3 This Agreement shall be subject to review in any proceeding the Commission may conduct regarding SCE's EDR program implementation.

21. ENTIRE AGREEMENT

This Agreement, including SCE's tariffs as filed with the Public Utilities Commission, constitutes the sole, only, and entire agreement and understanding between the Parties as to the subject matter of this Agreement with respect to Schedule EDR-E. Prior agreements, commitments or representations, whether expressed or implied, and discussions between Parties, shall not be construed to be a part of this Agreement.

22. AUTHORIZATION SIGNATURES

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized agents to be effective on the date of SCE's signature below.

By: SOUTHERN CALIFORNIA EDISON COMPANY

____

(Signature)

____

(Name)

____

(Title)

Southern California Edison Company

____

(Date)

By: CUSTOMER

____

(Signature)

____

(Name)

____

(Title)

____

(Customer)

____

(Date)

AFFIDAVIT FOR ECONOMIC DEVELOPMENT EXPANSION RATES

By signing this affidavit, an Applicant who expands load within the service territory of Southern California Edison (SCE) hereby certifies and declares under penalty of perjury under the laws of the State of California that the statements in the following paragraphs are true and correct:

1. But for the receipt of the applicable discounted EDR and the terms of the corresponding EDR-E Agreement, either on its own or in combination with an economic development incentive package, the Applicant's load would not be expanded within California.

2. Applicant has discussed with SCE the cost-effective conservation and load management measures the Applicant may take to reduce their electric bills and the load they place on SCE's system.

3. Customer confirms that its NAICS Code(s) and SIC Code(s) are as stated in the applicable EDR-E Agreement and that it is eligible for the applicable EDR-E schedule.

4. Customer certifies that all load subject to the applicable EDR-E Agreement represents load that is eligible for the applicable EDR-E schedule. (

D

Executed this ________day of ________________, ________.

By: APPLICANT____________________

Signature:__________________________

Name:______________________________

Title:_______________________________

Appendix C-3

EDR-R AGREEMENT

ECONOMIC DEVELOPMENT RATE-RETENTION AGREEMENT
(Post-Decision XXX)

This Agreement is entered into between ____ ("Customer"),____(Service Account(s)), located at____, and Southern California Edison ("SCE"), located at 2244 Walnut Grove Avenue, Rosemead, California 91770. This Agreement shall become effective as of the date set forth beneath SCE's signature on the signature page of this Agreement. This Economic Development Rate-Retention Agreement ("Agreement") provides Customer with a discount for electric energy purchased over the five-year term of the Agreement.

Additional applicable Service Accounts and Addresses are: (T)

Service Account	Service Address

This Agreement is a filed form tariff agreement authorized by the California Public Utilities Commission ("Commission") for use by SCE. No officer, inspector, solicitor, agent, or employee of SCE has any authority to waive, alter, or amend any part of this Agreement except as provided herein or as authorized by the Commission. This Agreement is to be used in conjunction with Schedule EDR-R of SCE's Commission-approved tariffs, and supplements the terms and conditions of Customer's electric service under Customer's Otherwise Applicable Tariff, which is Schedule ____ , and all related agreements.

The Parties agree as follows:

1. DEFINITIONS

As used in this Agreement, the following terms shall have the following meanings:

1.1 Added Facilities: Equipment or facilities that are in addition to, or in substitution for, standard facilities that SCE would normally install in order to provide electric service to Customer.

1.2 Agreement: This document and appendices, as amended from time to time.

1.3 Base Period Usage: As defined in Section 3 of this Agreement.

1.4 Customer: Customer as defined in SCE's Rule 1.

1.5 Forecast Maximum Demand: Customer's forecast of its Total Load maximum demand during the five years of this Agreement.

1.6 Incremental Added Facilities: Added Facilities that are required by SCE or requested by Customer to be installed in order to accommodate Customer's load, including any expansion under Schedule EDR-R.

1.7 Interest Rate: The 90-day commercial paper rate.

1.8 Liquidated Damages: Damages owed by Customer to SCE as provided in Section 10 of this Agreement.

1.9 Minimum Load: The minimum load Customer has agreed to purchase annually as established for Customer in Section 4.

1.10 Otherwise Applicable Tariff (OAT): The rate schedule, including any riders, under which Customer is taking electric service from SCE at the time of signing this Agreement or after, and any applicable successor schedule.

1.11 Party, Parties: The parties to this Agreement are SCE and Customer, as defined above.

1.12 Economic Development Rate-Retention (EDR-R): The rates and charges set forth in Schedule EDR-R, subject to the terms and conditions of this Agreement.

1.13 North American Industry Classification System ("NAICS") Code: An industry coding system developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about economic activity across North America.

1.14 Premises: This term shall mean at the physically and operationally related facility(s).

1.15 Small Customer Account: A Customer Account with load below 201 kW that is not subject to the 150 kW eligibility requirement.

1.16 Standard Industrial Classification ("SIC") Code: The published codes in the 1987 Standard Industrial Classification Manual issued by the Executive Office of the President, Office of Management and Budget, as may be updated in SCE's discretion.

1.17 Total Load: Customer's recorded (metered) load (energy and demand), as may be aggregated at the same Premises.

1.18 Uncontrollable Force(s): An Uncontrollable Force is an event or occurrence due to influences outside the reasonable control of either or both Parties that could not have been prevented by the exercise of due diligence.

2. ECONOMIC DEVELOPMENT RATE-RETENTION

2.1 Customer represents that their NAICS 4-digit Code is ____________________ ,or their SIC 3 or 4-digit Code is ___.________________

2.2 Customer further represents that it meets the applicability requirements of Schedule EDR-R.

2.3 Subject to the terms and conditions of this Agreement, SCE will provide 20 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by

SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.

2.4 Customer must maintain Total Load demands of at least 150 kW during each of the five years of service under this Agreement, either individually or on an aggregate basis for all accounts at the same Premises. Notwithstanding this provision, Customer can have a lower Total Load demand if the Service Account subject to this Agreement qualifies as a Small Customer Account.

2.5 If Customer plans to move or consolidate operations already located in SCE's service territory in connection with Customer's decision to remain in California, Schedule EDR-R shall apply to the Customer's operations as moved or consolidated, so long as all of the operations subject to Schedule EDR-R and this Agreement meet the applicability requirements of Schedule EDR-R.

2.6 If Section 2.5 is applicable, Customer must describe the locations that will be moved or consolidated, indicating the kW of each, as included in Forecast Maximum Demand. Customer must also describe any plans for expansion over the term of this Agreement.

3. BASE PERIOD USAGE

3.1 Base Period Usage must be established for each Customer to determine its Minimum Load. For Customers aggregating multiple accounts at a single Premises to meet the Total Load demand provisions specified above, BPU is established for the aggregation as a whole and not on an individual Service Account basis.

3.2 Base Period Usage is an average of Customer's historical monthly energy usage (kWh) and demand (kW) (provided Customer is served on an OAT with demand charges) by season and time-of-use where applicable, and is computed by SCE from Customer's 12 most representative continuous months of usage out of the past 24 months. Base Period Usage for energy consumption (kWh) shall be computed on an average hourly basis, and for billing shall be expanded by the applicable number of hours in the billing period. Ordinarily, Customer's Base Period Usage is based on the energy and demand recorded by SCE on a calendar-month basis. In the absence of calendar month data, 12 billing periods of Customer's billing history will be used, which may not add up to 365 days.

3.3 If Customer is subject to billing on a time-of-use basis but does not have the requisite historical data to determine its actual Base Period Usage, SCE shall estimate Customer's load characteristics, including estimated demand and energy usage on a time-of-use basis, using available data. That calculation shall be used as Customer's Base Period Usage until recorded load data becomes available to more definitively establish Customer's load characteristics. When SCE can more accurately estimate Customer's actual load characteristics, Customer's Base Period Usage shall be established based upon the new recorded data.

3.4 Base Period Usage is established as follows:

	Average Monthly Base Period Usage (kW[9])	Average Hourly Base Period Usage, (kWh)
Facilities Related Demand		N/A
Summer		
On-Peak		
Mid-Peak		
Off-Peak	________	________
OVERALL		
Winter		
Mid-Peak		
Off-Peak	________	________
Super-Off-Peak		
OVERALL		

Base Period Usage Facilities Related Demand is computed as follows:

1. Determine a Facilities Related Demand for each month in the period used to establish Base Period Usage that is the greater of:

   a. The maximum billing demand for the month, or

   b. 50% of the highest of all the billing demands in the period used to establish Base Period Usage.

2. Compute the average of the monthly Facilities Related Demands thus determined. This is Base Period Usage Facilities Related Demand.

An "XXX" entered above indicates that the entry is not applicable to Customer's Base Period Usage.

MINIMUM LOAD

4.1 Customer must maintain a Minimum Load for each year from the date service is first rendered under Schedule EDR-R for the five-year term of this Agreement.

4.2 The Minimum Load must be at least 150 kW, except for a Small Customer Account, or 75% of Base Period Usage. For Customers aggregating multiple accounts at a single Premises to meet the Total Load demand provisions specified above, the Minimum Load requirement applies to the aggregation as a whole and not on an individual Service account basis.

[9] kW BPU may not be applicable for Small Customer Accounts.

4.3 Small Customer Accounts notwithstanding, if during any year of service the Customer's Total Load maximum demand falls below the Minimum Load in any three months, the Customer's discounts under Section 2.3 above shall be suspended for the balance of the year and such suspension shall begin with the month of the third occurrence. Customer's discounts applicable to Total Load shall resume at the date specified in Section 5.2 of the following year, subject to the terms of this provision. For purposes of this section, a year of service commences with the start of the discount set forth above in Section 2.3. (

4.4 Any load reductions shown to be directly attributable to energy efficiency measures implemented after establishing Base Period Usage in this Agreement shall not adversely impact the calculation of Customer's Minimum Load. The imputed load reductions attributable to any energy efficiency measure implemented subsequent to the establishment of Base Period Usage shall be added back into the load calculation in the event that Customer's usage falls below the Minimum Load. Provided that Customer maintains usage of at least the Minimum Load, net of any energy efficiency impacts, all Customer discounts shall apply.

5. COMMENCEMENT OF SERVICE

5.1 SCE will begin providing service under Schedule EDR-R at the start of the next regular billing period following the date the Customer notifies SCE that service should begin under Schedule EDR-R, which date shall not be more than 12 months from the effective date of this Agreement.

5.2 If Customer notifies SCE that it plans to move or consolidate operations with qualifying load that will be billed under Schedule EDR-R, then SCE will begin providing service under Schedule EDR-R with the next regular billing period following the date Customer notifies SCE that service should begin under Schedule EDR-R, which date shall not be more than 12 months from the effective date of this Agreement.

5.3 Customer estimates that service under Schedule EDR-R shall commence at the start of the next regular billing period beginning after _________________ and shall provide SCE at least five business days' notice of any change in such date.

6. ADDED FACILITIES

An Added Facilities Contract, SCE's Form 16-308 or 16-309, shall be required if additional equipment or facilities are required for Added Facilities or Incremental Added Facilities.

7. ACKNOWLEDGMENT

7.1 Except as otherwise amended herein, Customer acknowledges that it is fully subject to all terms and conditions contained in Customer's OAT, or its successor rate schedule, all of SCE's rules, and all terms and conditions of service contained in SCE's Commission-approved tariffs. Any provision pertaining to either a peak period rate limiter or an average rate limiter does not apply.

7.2 Customer also acknowledges that SCE may request documentation to support Customer's signed Affidavit and may verify any supporting documentation and statements Customer has made in support of its signed Affidavit.

7.3 Customer also acknowledges that SCE is under a compliance mandate from the California Public Utilities Commission to provide to the Commission, under seal, (a) a list of the names and locations of its EDR participants, (b) their SIC Codes, (c) the total EDR discount provided to the Customer, (d) a listing of jobs retained or created during the relevant period that are attributable to the named EDR participant's involvement in the EDR program; and (e) the amount of the wage and benefits attributable during the relevant period to each category of job retained or created by the named EDR participant's involvement in the EDR program. Customer acknowledges that it is to provide to SCE **by no later than January 31 of each reportable year** any of the information above upon request in order to remain eligible to take service pursuant to this Agreement. Failure to timely furnish this information could lead, in SCE's sole discretion, to revocation of this Agreement. SCE shall use reasonable means to protect this data from public disclosure by redacting or aggregating it in any public filings.

8. TERM

8.1 This Agreement shall be effective for five years following the commencement of service under Schedule EDR-R pursuant to Section 5 of this Agreement.

8.2 At the end of the fifth year, Customer will no longer take service under Schedule EDR-R and will be billed only under its OAT effective with the start of the next regular billing period following the end of the fifth year of service under this Agreement.

8.3 This Agreement is not renewable at the expiration of its term, nor can the beneficiary of this Agreement take service on an EDR rate again for the same load served under this Agreement.

8.4. This Agreement must be executed prior to the date on which SCE's tariffs implementing the 2029 GRC Phase 2 become effective or when the EDR 300 MW cap from the latest Decision is met, whichever is earlier.

9. TERMINATION

This Agreement may be terminated (subject to payment of Liquidated Damages as provided in Section 10) by either party upon written notice as follows.

9.1 Termination for Misrepresentation or Fraud: SCE may terminate this Agreement upon five business days' notice if any representation made by Customer in this Agreement is untrue in any material respect, or if any statement in Customer's Affidavit was untrue, or if SCE determines that Customer was not eligible for Schedule EDR-R when this Agreement was signed, in which case Liquidated Damages as set forth in Section 10.3 shall be paid.

9.2 Termination at Customer's Request: Customer may request termination of this Agreement at any time by providing at least 60 days' written notice to SCE.

9.3 Termination For Nonpayment: SCE may terminate this Agreement if Customer fails to pay any amount due, under Schedule EDR-R within 30 days after receipt of notice of nonpayment from SCE. Customer shall be liable for all unpaid amounts and any accrued interest on the unpaid amounts.

9.4 Termination For Noncompliance: SCE may terminate this Agreement upon five business days' notice if Customer fails to comply with any term or condition of Schedule EDR-R or this Agreement.

9.5 Termination For Ineligibility: SCE may terminate this Agreement upon five business days' notice if it determines that Customer has become ineligible for Schedule EDR-R.

9.6 Termination For Failure To Maintain Minimum Load: SCE may terminate this Agreement if Customer fails to maintain its Minimum Load during any consecutive 12 month period or shuts down its operations. If Customer fails to maintain its Minimum Load, SCE must provide Customer at least 90 days' notice of termination and Customer shall have the opportunity to increase its load to the Minimum Load and demonstrate to SCE's satisfaction that it will continue to use its Minimum Load for the remaining term of this Agreement.

9.7 Termination For Failure To Commence Service: SCE may terminate this Agreement if Customer does not begin service within 12 months after the date this Agreement was executed.

9.8 Termination for Ceasing Operations: SCE may terminate this Agreement upon five business days' notice if Customer ceases the operations to which this Agreement applies or moves such operations out of SCE's service territory.

10. LIQUIDATED DAMAGES

10.1 Upon termination of this Agreement, prior to its five-year term pursuant to Sections 9.1, 9.2, 9.3, 9.4, 9.5, or 9.6, Customer shall be required to pay SCE Liquidated

Damages. The Liquidated Damages are required to ensure that neither SCE nor its ratepayers are financially or otherwise damaged if this Agreement is prematurely terminated before the end of its term. (Excludes business closure, relocation, or reduction in load without relocation)

10.2 It would be extremely difficult for the Parties to identify the amounts of increased or additional costs attributable to termination of this Agreement. Parties agree the Liquidated Damages specified herein are a reasonable approximation of damages which SCE and its ratepayers may incur as a result of such termination, and that the damage amount does not represent a penalty.

10.3 For termination under Section 9.1 above, Liquidated Damages under this Agreement shall be an amount equal to 200 percent of the cumulative difference between (i) the amount the Customer would have paid for its energy and demand if billed at their OAT, from the date service was first rendered under Schedule EDR- R, to the date of termination, and (ii) the amount billed to Customer under this Agreement and Schedule EDR-R during the same period.

10.4 For termination under Sections 9.2, 9.3, 9.4, 9.5, or 9.6 above Liquidated Damages under this Agreement shall be an amount equal to 100 percent of the cumulative difference between (i) the amount billed to Customer under Schedule EDR-R from the date service was first rendered under Schedule EDR-R to the date of termination, and (ii) a "proxy" bill calculation based on a declining discount starting at 20 percent of the Customer's OAT bill in year one with that annual discount reduced by 4 percent each year thereafter during the same period, *i.e.,* a discount of 16 percent in year 2, 12 percent in year 3, 8 percent in year 4, and 4 percent in year 5, plus interest on that difference (at the Interest Rate) to the date of payment. Should a Customer's usage increase such that cumulative liquidated damages become negative upon contract termination, under no circumstances will SCE be liable for paying liquidated damages to a Customer. (

10.5 After termination of this Agreement for any cause, Customer shall be billed at its OAT.

10.6 The limitations of Rule 17 of SCE's Commission-approved Tariffs shall not apply to amounts payable under this Agreement.

10.7 SCE may in its discretion require Customer to establish a letter of credit or other security as a condition to providing service under Schedule EDR-R to secure payment of any Liquidated Damages.

11. UNCONTROLLABLE FORCE

11.1 Neither Party shall be considered to be in default in the performance of any obligation under this Agreement, except for obligations to pay money, when and to the extent that failure of performance shall be caused by an Uncontrollable Force.

11.2 If either Party, because of an Uncontrollable Force, is rendered wholly or partly unable to perform its obligations under this Agreement, the Party shall be excused from whatever performance is affected by the Uncontrollable Force to the extent the following conditions are met.

11.2.1 The suspension of performance is of no greater scope and of no longer duration than is required by the Uncontrollable Force.

11.2.2 The nonperforming Party uses its best efforts to cure its inability to perform. This subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty.

11.2.3 When the nonperforming Party is able to resume performance of its obligations under this Agreement that Party shall give the other Party written notice to that effect immediately.

11.3 Nonperformance due to Uncontrollable Force shall be excused, provided Party can demonstrate that the Uncontrollable Force was owing to causes outside its reasonable control and the occurrence of the Uncontrollable Force could not have been prevented by the exercise of due diligence.

11.3.1 Accordingly, nonperformance shall be excused from the date of the occurrence of the Uncontrollable Force, provided the nonperforming Party has given the other Party written notice describing the particulars of the occurrence within two weeks of the event.

11.3.2 Accordingly, nonperformance shall be excused from the date on which the nonperforming Party gives the other Party written notice describing the particulars of the occurrence of the Uncontrollable Force, if such written notice is given more than two weeks after the Uncontrollable Force occurred.

11.4 If Customer experiences an Uncontrollable Force that prevents Customer from complying with Schedule EDR-R and this Agreement, Customer may request that SCE suspend the terms of Schedule EDR-R and this Agreement for the duration of the Uncontrollable Force. Customer will be billed at their OAT for the duration of the suspension of this Agreement. Resumption of the terms of Schedule EDR-R and this Agreement shall commence with the next regularly scheduled billing period. In addition, the term of this Agreement will be extended for up to 12 months beyond the term originally established in this Agreement by the length of time this Agreement was suspended.

11.5 The occurrence of an Uncontrollable Force shall not (i) prevent SCE from terminating this Agreement in accordance with Sections 9.4 and 9.5 or (ii) extend the period any level of discount is available as provided in Section 2.3.

11.6 If the Uncontrollable Force causing the nonperformance is caused by the actions or inactions of legislative, judicial or regulatory agencies, or other proper authority, this Agreement may be amended to comply with the legal or regulatory change causing the nonperformance. Any such amendment must be first authorized by the Commission prior to implementation.

12. DAMAGE LIMITATION

SCE shall not be liable for any consequential, incidental, indirect, or special damages, whether in contract, tort, or strict liability including, but not limited to, lost profits and loss of power resulting from power outages or other electric service interruptions or from SCE's performance or nonperformance of its obligations under this Agreement or in the event of termination of this Agreement.

13. INDEMNITY

Customer shall, at its own cost and expense, defend, indemnify, and hold harmless SCE, its officers, agents, employees, assigns, and successors in interest, from and against any and all liability, damages, losses, claims, demands, actions, cause of action, costs, including attorney's fees and expenses, or any of them, resulting from the death or injury to any person or damage to any property caused by Customer, its employees, officers and agents, or any of them, and arising out of the performance or non-performance of its obligations under this Agreement. Termination of this Agreement shall not exempt Customer from the terms and conditions of this Section.

14. ASSIGNMENT OF AGREEMENT

Customer shall not assign this Agreement or any part or interest thereof, to a third party without the prior, written consent of an authorized representative of SCE. Any assignment made without such consent shall be void and of no effect. Further, any assignment made under this Agreement shall be subject to any applicable Commission authorization or regulation except as waived by the Commission.

15. AMENDMENT

Any changes or amendments to this Agreement must be in writing and must be executed by the Customer and SCE and, if required, be approved by the Commission.

16. NOTICE

Any notice either Customer or SCE may wish to provide the other regarding this Agreement must be in writing and may be transmitted by hand, fax, email or postal mail. Notices delivered by hand shall be deemed effective when delivered. Notices delivered by fax, email and mail shall be deemed effective when received.

Customer: ______________________________

(name)

____

(title)

____

(party)

____

(address)

____

(city, state, & zip code)

SCE: Manager, Economic Development Services
Southern California Edison Company
6070-F No. Irwindale Avenue
Irwindale, CA 91702

17. NON-WAIVER

The failure of either Party to enforce any of the terms and conditions or to exercise any right or privilege in this Agreement shall not be construed as a waiver of any such terms and conditions or rights or privileges, and the same shall continue and remain in force and effect as if no such failure to enforce or exercise had occurred.

18. SEVERABILITY

In the event that any of the provisions, or portions thereof, of this Agreement are held to be unenforceable or invalid by the Commission, or any court of competent jurisdiction, the validity and enforceability of the remaining provisions or any portion thereof shall not be affected. However, should either party determine, in good faith, that such unenforceability renders the remaining provisions of this Agreement economically infeasible or disadvantageous, said party may terminate this Agreement upon 15 days' notice, except that the provisions of Section 10, Liquidated Damages, shall apply to any such termination.

19. APPLICABLE LAWS, RULES, AND REGULATIONS

This Agreement shall be subject to, and interpreted under, the laws, rules, and regulations of the State of California and the Commission, and under SCE's Commission-approved Tariff Schedules and Rules. To the extent there are any inconsistencies between this Agreement and SCE's other tariffs, this Agreement shall control.

20. CALIFORNIA PUBLIC UTILITIES COMMISSION

20.1 This Agreement shall at all times be subject to such changes or modifications by the Commission as said Commission may, from time to time, direct in the exercise of its jurisdiction.

20.2 Notwithstanding any other provisions of this Agreement, SCE has the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in rates, charges, classification, service, or rule, or any agreement relating thereto.

20.3 This Agreement shall be subject to review in any proceeding the Commission may conduct regarding SCE's EDR program implementation.

21. ENTIRE AGREEMENT

This Agreement, including SCE's tariffs as filed with the Public Utilities Commission, constitutes the sole, only, and entire agreement and understanding between the Parties as to the subject matter of this Agreement with respect to Schedule EDR-R. Prior agreements, commitments or representations, whether expressed or implied, and discussions between Parties, shall not be construed to be a part of this Agreement.

22. AUTHORIZATION SIGNATURES

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized agents to be effective on the date of SCE's signature below.

By: SOUTHERN CALIFORNIA EDISON COMPANY	By CUSTOMER
(Signature)	(Signature)
(Name)	(Name)
(Title)	(Title)
Southern California Edison Company	(Customer)
(Date)	(Date)

AFFIDAVIT FOR ECONOMIC DEVELOPMENT RETENTION RATES

By signing this affidavit, an Applicant who retains load in the service territory of Southern California Edison (SCE) hereby certifies and declares under penalty of perjury under the laws of the State of California that the statements in the following paragraphs are true and correct:

1. But for the receipt of the applicable discounted EDR and the terms of the corresponding EDR-R Agreement, either on its own or in combination with an economic development incentive package, the Applicant's load would not be retained within California.

2. Applicant has discussed with SCE the cost-effective conservation and load management measures the Applicant may take to reduce their electric bills and the load they place on SCE's system.

3. Customer confirms that its NAICS Code(s) and SIC Code(s) are as stated in the applicable EDR-R Agreement and that it is eligible for the applicable EDR-R schedule.

4. Customer certifies that all load subject to the applicable EDR-R Agreement represents load that is eligible for the applicable EDR-R schedule and is existing load that is being retained within California.

Executed this ________day of ________________, ________.

By: APPLICANT__________________

____

Signature:

____

Name:

____

Title:

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

ELECTRIC VEHICLE RATE DESIGN SETTLEMENT AGREEMENT

Dated: **September 12, 2025**

Electric Vehicle Rate Design Settlement Agreement

Table of Contents

Electric Vehicle Rate Design Settlement Agreement

Table of Contents (Continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

ELECTRIC VEHICLE RATE DESIGN SETTLEMENT AGREEMENT

This Electric Vehicle Rate Design Settlement Agreement (EV) Agreement or Settlement Agreement) is entered into by and among the undersigned Parties hereto, with reference to the following:

1. PARTIES

The Parties to this Agreement are Southern California Edison Company (SCE), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates),[1] CALSTART, Inc., Electrify America, LLC, EVgo Services, LLC, Small Business Utility Advocates (SBUA), Solar Energy Industries Association (SEIA), Vehicle-Grid Integration Council (VGIC), Terawatt Infrastructure, Inc. (Terawatt), and Walmart Inc., referred to hereinafter collectively as Settling Parties or individually as a Party.

A. SCE is an investor-owned public utility (IOU) and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. Cal Advocates represents the interests of public utility customers. Its goal is to obtain the lowest possible rate for service consistent with safe, reliable service, and the State's environmental goals. Pursuant to California Public Utilities Code Section 309.5(a), Cal

[1] Cal Advocates is a party to all provisions of this Settlement Agreement except Section 5.C(4), "Load Factor Based Rate Option Proposal."

Advocates is directed to primarily consider the interests of residential and small commercial customers in revenue allocation and rate design matters.

C. CALSTART, Inc. headquartered in California, is a globally renowned 501(c)3 non-profit organization dedicated to the advancement of zero emission vehicle and infrastructure technology. With a global consortium of over 200 technology, government, industry, and community partners, CALSTART has worked for 30+ years to accelerate the commercialization and deployment of advanced technologies and solutions.

D. Electrify America, LLC is an electric vehicle charging network with more than 4,400 fast chargers at more than 1,000 locations across the United States.

E. EVgo Services, LLC is one of the nation's leading public fast charging providers. With more than 1,100 fast charging stations across over 40 states, EVgo strategically deploys localized and accessible charging infrastructure by partnering with leading businesses across the U.S., including retailers, grocery stores, restaurants, shopping centers, gas stations, rideshare operators, and autonomous vehicle companies.

F. SBUA is a nonprofit organization that represents, protects, and promotes the interests of the small business utility customers.

G. SEIA is the national trade association of the solar and storage industry. Through outreach and education, SEIA and its over 1200 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy and storage.

H. Vehicle Grid Integration Council is a 501(c)6 membership-based advocacy group committed to advancing the role of electric vehicles and vehicle-grid integration through policy development, education, outreach, and research.

I. Terawatt provides reliable charging solutions for the future of fleet transportation. The company designs, operates, and owns electric vehicle charging hubs for fleet operations combining property assets with energy and charging expertise. Terawatt was founded, in the absence of anything like it, to be the nation's reliable, long-term partner in the inevitable transition to all-electric transportation.

J. Walmart Inc. is a multinational retail corporation that operates 303 retail units, 17 distribution centers, and four fulfillment centers and employs over 104,000 associates in California.

2. DEFINITIONS

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "Commission" or "CPUC" means the California Public Utilities Commission.

B. "Default Rate" means the rate schedule on which the customer is automatically placed when starting service unless the customer requests otherwise.

C. "DER" means "Distributed Energy Resource."

D. "EV" means "electric vehicle."

E. "MCRA Settlement Agreement" means the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on June 30, 2025.

F. "OAT" means the customer's otherwise applicable tariff.

G. "Paired storage" means BTM electric storage technology including, but not limited to, electric battery systems, that are combined behind the same meter or billed on the same service account as other DERs, usually solar.

H. "RDW" means Rate Design Window proceeding.

I. "RECC" or "Real Economic Carrying Charge," means a constant payment in real dollars that includes the recovery of the capital investment, earnings, taxes, and other capital carrying costs. The RECC when escalated at the rate of inflation over the life of the asset recovers the net present value of revenue requirement of a utility investment. It also represents the value of deferring a utility investment by a year.

J. "Standalone storage" means BTM electric storage technology including, but not limited to, electric battery systems that are not combined behind the same meter or billed on the same service account as other DERs.

K. "ZEV" means Zero-Emissions Vehicle.

3. **RECITALS**

A. In Phase 2 of SCE's 2025 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

B. On March 29, 2024, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application (A.)24-03-019. On August 26, 2024, SCE filed an Amended Application and served amended testimony regarding certain revenue allocation proposals.

C. On November 1, 2024, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a June 3, 2024 prehearing conference.

D. The Public Advocates Office served its initial testimony on November 22, 2024. Intervenors, including the Settling Parties to this Agreement, served their initial prepared testimony on January 8, 2025.

E. The following intervenors submitted prepared testimony regarding EV Rate Design Issues: Cal Advocates, CALSTART, Inc, Electrify America, LLC, EVgo Services, and Walmart Inc.

F. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on January 16, 2025.

G. Continuing settlement discussions occurred among the parties after January 16, 2025.

H. Appendix A to this Agreement provides a comparison of the Settling Parties' positions, where applicable, related to EV Rate Group rate design issues that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and

Appendix A, the terms of this Agreement shall control. Appendix B provides illustrative EV Rate Group rates resulting from this Settlement Agreement. Consistent with Paragraph 11 of this Settlement Agreement, these class average summaries are for illustrative purposes only. The rate summaries will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of the MCRA Settlement Agreement when rates are first implemented pursuant to the provisions of this Agreement.

I. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to rate design regarding EV Rate Group customers as set forth in this Agreement beginning with the implementation of a CPUC decision approving this Agreement, and, in consideration of the mutual obligations, covenants and conditions contained herein, have reached agreement as indicated in Paragraphs 4 and thereafter of this Agreement.

4. BACKGROUND

In SCE's 2021 GRC Phase 2 proceeding, the Settling Parties agreed to a settled position with regard to EV rates that was consistent with Decision (D.)18-05-040, in which the Commission adopted a "Joint Stipulation"[2] outlining an agreed upon methodology for SCE's rate design for then-new EV rates, including the TOU-EV-8 and TOU-EV-9 rates addressed in this Settlement Agreement. Specifically, D.18-05-040 provided (with emphasis added):

> [Ordering Paragraph] 43. ***Southern California Edison Company (SCE) may offer its Commercial Electric Vehicle Rate proposal as modified by the Joint Stipulation set forth in Exhibit Joint-12.*** SCE may offer the transmission related proposals in Exhibit Joint-12 on a temporary three-year basis, provided SCE files a Single Issue 205 filing with the Federal Energy Regulatory Commission (FERC) for approval of the 70/30 proxy temporary rates and takes the appropriate steps to complete a transmission marginal cost study in its General Rate Case phase 2. In the event FERC does not approve the 70/30 proxy split, SCE may implement its proposed commercial rate EV rates using the transmission cost allocation currently approved by FERC.

[2] The signatories to the Joint Stipulation were Cal Advocates, Natural Resources Defense Council. Siemens, Sierra Club, Environmental Defense Fund and the Coalition of California Utility Employees.

Settling Parties agreed to extend the energy-only structure of TOU-EV-8 and TOU-EV-9 beyond the five-year timeline initially established in D.18-05-040, a modification that was consistent with the Joint Stipulation's offramp for proposals made in a GRC Phase 2. The Settling Parties further agreed at that time, that if the energy-only rate structures remained in effect at the time SCE files its next GRC Phase 2, then SCE would either propose to begin the gradual introduction of demand charges or propose rate structure updates for TOU-EV-8 and TOU-EV-9 that address how demand charges should be implemented.[3]

5. AGREEMENT

Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit, or a claim by a Settling Party that its position has greater or lesser merit than the position taken by any other Settling Party. This Agreement is subject to the express limitation on precedent as provided in Commission Rule 12.5 and as described in Paragraph 11. Unless specifically stated otherwise herein, this Agreement and its terms are intended to remain in effect until a decision is implemented in Phase 2 of SCE's next GRC.

A. Illustrative Rates

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the EV share of the consolidated revenue requirement of $17,466 million described in more detail in Paragraph 4.B of the MCRA Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the MCRA Settlement Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

B. Common Rate Design Elements

Consistent with SCE's Application, rate structures for the EV Rate Groups will generally consist of Customer Charges, TOU Energy Charges, and FRD Charges for the TOU-EV-7 rate schedule.

---

[3] Settling Parties also agreed that this Settlement Agreement does not restrict the Commission from modifying TOU-EV-8 and TOU-EV-9 in any proceeding relating to transportation electrification.

TOU-EV-8 and TOU-EV-9 rate schedules will continue to retain an all-energy TOU rate structure with applicable customer charges.

1) <u>TOU Periods and Seasonal Definitions</u>

SCE's existing TOU periods and summer/winter season definitions for EV customers shall not be modified from their current definitions. (*i.e.,* summer: June through September; winter: October through May).

2) <u>Customer Charges</u>

Customer Charges shall be derived based on SCE's as-proposed RECC customer marginal cost method, but adjusted to recover a portion (*i.e.*, the first 50 kVA) of the FLT costs in the FRD Charge. Customer Charges shall be set at the full EPMC level for all customers in the EV Rate Groups. Illustrative monthly Customer Charges are listed in Table 1, below:

Table 1: Illustrative Monthly Customer Charges

Rate Group	Customer Charge
TOU-EV-7	$10.79
TOU-EV-8	$232.74
TOU-EV-9	SEC: $1,113.65 PRI: $313.25 SUB: $8,512.50

When this Agreement is first implemented in 2026, these estimated Customer Charges shall be adjusted, as necessary, consistent with the customer charge treatment of the then-current revenues allocated to each rate group in accordance with the MCRA Settlement Agreement and specific customer charge treatment described in this agreement or the class specific Settlement Agreements.[4] Thereafter, these Customer Charges shall be adjusted on a Functional SAPC basis.

---

4 *See* Paragraph 4.B.6 of the MCRA Settlement Agreement.

3) Energy Charges

Proposed Energy Charges based on SCE's October 2024 consolidated revenue requirement are set forth in Appendix B.[5] When this Agreement is first implemented in 2026, these estimated Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MCRA Settlement Agreement.[6] Thereafter, these estimated Energy Charges shall be adjusted consistent with Paragraph 4.B.7 of the MCRA Settlement Agreement when SCE's authorized revenue requirements change.

a) Non-Generation-Related Energy Charges

Energy Charges that are designed to recover revenues associated with the following categories -- transmission (TOTCA), distribution,[7] public purpose programs, new system generation service, nuclear decommissioning, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and the CPUC reimbursement fee -- shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the MCRA Settlement Agreement.

b) Generation-Related Energy Charges

Except where otherwise specified in this Agreement, generation-related Energy Charges shall be established based on the TOU marginal energy costs used in the MCRA Settlement Agreement.

C. EV Rates [8]

1) Schedule TOU-EV-7

TOU-EV-7 is a separately metered rate applicable solely to the charging of EVs for customers with demands of 20 kW or less. With regard to distribution charges, SCE will keep in

---

[5] The estimated consolidated revenue requirement, as defined in Paragraph 4.B.1 of the MCRA Settlement Agreement, is $17,466 million.

[6] *See* Paragraph 4.B.6 of the MCRA Settlement Agreement.

[7] The recovery of distribution revenues via Energy Charges varies based on the specific rate option, and is further discussed in the "Base and Optional Rates and Rate Design" section below.

[8] Cal Advocates joins the Settlement Agreement subject to its previously stated objection to the Load Factor Based Rate Option Proposal set forth herein.

place a feature that limits distribution charges for eligible TOU-EV-7 customers.[9] Because the EV rates feature a combination of distribution energy and demand charges, the demand comparison calculation and any resulting distribution "credit" will apply to both energy and demand charges.

Separately, the customer charge for TOU-EV-7 shall be set at $10.79 per month ($0.355 per day). The reduced customer charge is intended to recover the cost of the additional meter and associated on-going customer service costs, while recognizing that for a portion of TOU-EV-7 customers, the service point and other associated facility costs are recovered through the customer charge of the primary (main site) infrastructure. The revenue deficiency generated by this customer charge benefit will be collected through flat energy charges in order to maintain a revenue neutral rate design.

For distribution, all Peak-capacity, Grid-capacity, and the balance of the customer charge revenues are recovered via volumetric TOU Energy charges across both the summer and winter periods for the default Option E rates. The seasonal delta across the average summer and winter rates are held at the seasonal delta of the default TOU-GS-1 Option E rate. Additionally, the summer and winter TOU ratios are consistent with the TOU-GS-1 default Option E rate. For TOU-EV-7 Option D, an FRD charge is introduced to recover a portion of the Grid-related cost thereby reducing the volumetric TOU Energy charges by an equal cents-per-kWh offset.

For generation, all capacity and energy related costs are recovered via volumetric TOU Energy charges across both the summer and winter periods. The seasonal delta across the average summer and winter rates are consistent with the default TOU-GS-1 Option E rate. Additionally, the summer and winter TOU ratios are consistent with the default TOU-GS-1 Option E rate.

2) Schedules TOU-EV-8 & TOU-EV-9

Schedules TOU-EV-8 and TOU-EV-9 are separately metered rates applicable solely to the charging of EVs for customers. With regard to distribution charges, SCE will continue to offer a feature that limits distribution charges for TOU-EV-8 and TOU-EV-9 customers. The current

---

[9] TOU-EV-7 customers who are collocated on the same premises as the General Service account.

versions of TOU-EV-8 and TOU-EV-9 reflect an energy-only rate structure. D.18-05-040 contemplated ending this energy-only rate structure, and beginning a gradual introduction of demand charges, five years after these two rates were originally authorized. For the energy-only structure Settling Parties agreed to extend the current versions of TOU-EV-8 and TOU-EV-9, beyond the five-year timeline established by D.18-05-040, and the incremental extension settled in the 2021 GRC Phase 2 proceeding. Settling Parties also agreed that this Settlement Agreement did not restrict the Commission from modifying TOU-EV-8 and TOU-EV-9 in any proceeding relating to transportation electrification. Adjustments to account for customers participating in the TOU-EV-8 and TOU-EV-9 rates will be made such that the revenue deficiency is contained within the individual rate class (*e.g., TOU-GS-2, TOU-GS-3, TOU-8)* in which the deficiency exists. The energy-only rate structure is also available to Direct Current Fast Charger (DCFC) to continue to provide stability to the developing DCFC industry. Settling Parties agreed to the following rate design criteria for TOU-EV-8 and TOU-EV-9 rates.

- ***<u>TOU-EV-8</u>***:
    - For distribution, all Peak-capacity and Grid-capacity costs are recovered via volumetric TOU Energy charges across both the summer and winter periods. The proportion of seasonal revenue recovery is held constant relative to the current (October 2024) TOU-EV-8 rate structure. For summer, the Off- and Mid- peak rates, and for winter, the Super-Off and Off- peak rates are set based on marginal cost, and Summer On-peak and Winter Mid-Peak rates are calculated to maintain revenue neutrality by season.
    - For generation, all capacity and energy related costs are recovered via marginal cost based volumetric TOU Energy charges across both the summer and winter periods.
- ***<u>TOU-EV-9</u>***:
    - For TOU-EV-9-SEC, the customer charge is set at 110 percent of unscaled marginal cost. The remainder of the customer charge revenue along with Peak capacity and Grid-related costs are recovered via volumetric TOU Energy

charges across both the summer and winter periods. For TOU-EV-9-SEC and TOU-EV-9-PRI, the seasonal revenue proportion is based on the marginal cost proportion of summer and winter revenues. Summer off-peak rates are set based on marginal cost and On- and Mid-peak rates are held equal and calculated to maintain revenue neutrality for the summer. Winter Mid, Winter-Off, and Super-off peak rates were set based on prescribed TOU ratios of 2.3/2.3/1.0 respectively and calculated to maintain revenue neutrality for the winter.

- For TOU-EV-9 SUB distribution, Peak-capacity and Grid-related costs are recovered via volumetric TOU Energy charges across both the summer and winter periods. The seasonal revenue proportion is based on the marginal cost proportion of summer and winter revenues. Summer off-peak rates are set based on marginal cost and On- and Mid-peak rates are held equal and calculated to maintain revenue neutrality. Winter Mid, Winter-Off, and Super-off peak rates were set based on prescribed TOU ratios of 3.75/3.75/1.0 respectively and calculated to maintain revenue neutrality for the winter.
- For TOU-EV-9-SEC, PRI and SUB generation, all capacity and energy related costs are recovered via marginal cost based volumetric TOU Energy charges across both the summer and winter periods.

3) <u>Schedule Option H</u>

Using SCE's analysis on Option S as the foundation for this new rate option, Settling Parties agree to introduce a TOU-Option H schedule for the TOU-GS-2, TOU-GS-3, TOU-8-SEC rate classes. For customers with BTM storage that are enrolled on Option H of the noted rate classes above, systems qualifying under this schedule must have a minimum discharge capacity equal to or greater than 10 percent of the Customer's annual peak demand, as recorded over the previous 12 months with the associated minimum kWh determined by a minimum discharge duration of four hours per day. The Option H schedule for all three rate classes is designed with the same rate design parameters. For distribution, the rate structure introduces a Daily Peak-TRD charge to capture a portion of the Peak-capacity and Grid-related costs, and an FRD exclusion window where the FRD charges do not apply from 8 a.m. to 1 p.m. The FRD charge is set at 45% of the Option E FRD charge for TOU-8-SEC, 46% for TOU-GS-3, and 40% for TOU-GS-2. The remainder of the Option E FRD revenues is then designed for recovery in the Daily Peak-TRD charge. The residual portion of design demand revenues are recovered via volumetric TOU Energy charges that are set based on the TOU ratios of the respective class Option E rates and calculated to maintain revenue neutrality in each season.

For generation, the design is identical to the Option E rate design where the recovery of energy and capacity revenues is via a TRD Charge set at twenty-five percent (25%) of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

4) <u>Load Factor Based Rate Option Proposal</u>

a) <u>Framework</u>

Settling Parties, except Cal Advocates, agree to introduce a load factor-based rate option applicable to eligible customers on TOU-EV rates. The rate option will have the effect of converting a three-part rate, consisting of customer charge ($/mo.), energy charges ($/kWh) and demand charges $/kW), into a two-part rate consisting of customer and energy charges. The intent of the option is to provide a stable affordable rate structure to medium- heavy-duty charge facilities during the charging entities' initial ramp up years when charging facility load factors are expected to be below 15%. Each participating facility will be eligible to participate on the rate rider for an initial ramp-up period of three years, which begins at the commencement of energization. The participating facility's load factors will be monitored on a monthly basis to establish continued eligibility - If a facility's load factor exceeds the upper threshold for three consecutive months, then the facility will be moved to the then default EV rate option and the customer cannot return to the rate option even if the customer's load factor declines below the threshold. The customer can also select a rate option other than the default EV rate option. If Load Factor rate rider option is selected by the customer, the rider will apply when the customer is energized and will remain in effect over the three-year term unless the load factor threshold is exceeded as discussed above.

b) <u>Rate Elements</u>

1) The LFR will be available to customers who would otherwise be served on the then default TOU-EV-8 and TOU-EV-9 rate schedules and are expected to have load factors equal to or below 15%.

2) The rate option will be applied to the applicable tariff through two rate components, these include:

   a) A demand charge credit on a $/kW basis to offset the Facilities Related Demand (FRD) and or Time Related Demand (TRD) charge(s) and;

   b) An energy charge on a flat $/kWh basis to recover the revenue deficiency produced by the demand charge credit, which is intended to maintain the EV rate revenue neutrality.

3) Participating customers will have access to the LFR over the initial three years of operations at the participating facility starting from the participating service account's energization date.

   a) At the end of the three-year period the participating service account will be moved to the then default EV tariff rate.

   b) Customers will also have the option of selecting an eligible tariff other than the default EV tariff rate.

4) SCE will monitor the charging facility load factors over each billing period to determine eligibility for the LFR.

   a) If the facility load factor exceeds the threshold for three consecutive billing periods, then the LFR will no longer apply and the facility will be moved to the then default EV tariff rate.

      i) Customers will also have the option of selecting an applicable tariff other than the default EV tariff.

ii) Customers may not return to the rate option thereafter, even if load factor declines below the threshold.

b) Effective date is date customer is energized and will remain in effect if the facility (service account) load factor is equal to or below the threshold for up to twelve consecutive billing periods within the LFR eligibility period (i.e., first three years of operations starting from the energization date).

i) The facility must be on a default EV rate option in order to receive the LFR adjustment.

5) Zero-Emissions Vehicle Reporting

SCE proposed to discontinue reporting on participation levels for zero-emission vehicle loads on Option E rate schedules and EV specific rates. Cal Advocates opposed SCE's proposal to remove this reporting requirement, claiming it would be premature to stop reporting that would provide valuable insights on customer preferences and perceptions of rate options. SCE has not reached the trigger to submit an Advice Letter and believes that this prescribed reporting should be discontinued. The tracking process is complicated, time-intensive, and insights gained from the current end use load extraction methods are time intensive and can require expensive field verification methods to ensure accuracy of the estimated EV load on Option E. Settling Parties agree to modify the reporting requirements to provide enrollment number details specific to customer migrations from EV rates to Option E rates.

D. Implementing Future Revenue Changes in Rates

As described in the MCRA Settlement Agreement,[10] when SCE's authorized revenues change in the future, SCE will first adjust rate levels for the default rate schedules (without CPP elements), *e.g.*, Schedules TOU-GS-2-D, TOU-GS-3-D, and Schedule TOU-8-Sec-D, using a Functional SAPC adjustment. SCE will then rebalance optional rate levels to ensure revenue neutrality between the

[10] *See* Paragraph 4.B.7 of the MCRA Settlement Agreement.

default rate schedule and the optional rate schedules within each rate class. For example, generation revenue changes resulting from SCE's ERRA proceedings shall be allocated on a Functional SAPC basis, *i.e.*, the revised SCE generation revenue requirement will be allocated by applying a generation-level SAPC scalar to the relevant generation-related charges, based on the difference between present rate revenues and proposed rate revenues for the default rate schedules. The optional rate schedules will then be adjusted to ensure revenue neutrality on a functional basis within each rate class, except for TOU-GS-3 as specified in Paragraph 4.C.2 above.

6. IMPLEMENTATION OF SETTLEMENT AGREEMENT

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1, 2026.

7. INCORPORATION OF COMPLETE AGREEMENT

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties. If the Commission does not approve this Agreement without modification, the terms and conditions reflected in this Agreement shall no longer apply to the Settling Parties.

8. RECORD EVIDENCE

The Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

9. SIGNATURE DATE

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

10. REGULATORY APPROVAL

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's Test Year 2025 GRC. The Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. However, in the event the Commission modifies the Load Factor Based Rate Option Proposal, Cal Advocates shall have no obligation to negotiate a resolution acceptable to Settling Parties. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

11. COMPROMISE OF DISPUTED CLAIMS

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

12. NON-PRECEDENTIAL

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Settlement Agreement is not precedential in any other pending or future proceeding before this Commission, except as expressly provided in this Settlement Agreement.

The Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2025 GRC, or earlier if invited to do so by the Commission in, for example, a relevant Rulemaking proceeding.

13. PREVIOUS COMMUNICATIONS

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to the subject matter of this Settlement Agreement. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

14. NON-WAIVER

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

15. EFFECT OF SUBJECT HEADINGS

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

16. GOVERNING LAW

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

17. NUMBER OF ORIGINALS

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: September 12, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Daniel Hopper

By: Daniel Hopper
Title: Managing Director, Regulatory Policy

Dated: September __, 2025

Public Advocates Office (Public Advocates Office joins all provisions of this Settlement Agreement except Section 5.C(4))

By: Michael Campbell
Title: Deputy Director

Dated: September 12, 2025

CALSTART, Inc.

/s/ Marc Gottschalk

By: Marc Gottschalk
Title: Chief Legal Counsel

Dated: September 12, 2025

SOLAR ENERGY INDUSTRIES ASSOCIATION

/s/ Jeanne Armstrong

By: Jeanne Armstrong
Title: Senior Regulatory Counsel

Dated: September 12, 2025

Electrify America, LLC

/s/ Steve Bright

By: Steve Bright
Title: Senior Counsel

17. NUMBER OF ORIGINALS

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: September __, 2025

SOUTHERN CALIFORNIA EDISON COMPANY

By: Daniel Hopper
Title: Managing Director, Regulatory Policy

Dated: September 11, 2025

Public Advocates Office (Public Advocates Office joins all provisions of this Settlement Agreement except Section 5.C(4))

By: Michael Campbell
Title: Deputy Director

Dated: September __, 2025

CALSTART, Inc.

By: Marc Gottschalk
Title: Chief Legal Counsel

Dated: September , 2025

SOLAR ENERGY INDUSTRIES ASSOCIATION

By: Jeanne Armstrong
Title: Senior Regulatory Counsel

Dated: September _, 2025

Electrify America, LLC

By: Steve Bright
Title: Senior Counsel

Dated: September 12, 2025

SMALL BUSINESS UTILITY ADVOCATES

By: Britt Marra
Title: Executive Director

Dated: September 12, 2025

VEHICLE GRID INTEGRATION COUNCIL.

By: Zach Woogen
Title: Executive Director

Dated: September 12, 2025

WALMART INC.

By: Julie Clark
Title: Attorney

Dated: September 12, 2025

Terawatt Infrastructure Inc.

By: Jason Berry
Title: Vice President, Energy

Dated: September 12, 2025

EVgo SERVICES LLC

By: Sara Rafalson
Title: Executive Vice President, External Affairs

Dated: September 12, 2025 SMALL BUSINESS UTILITY ADVOCATES

____

By: Britt Marra
Title: Executive Director

Dated: September 12, 2025 VEHICLE GRID INTEGRATION COUNCIL.

By: Zach Woogen
Title: Executive Director

Dated: September 12, 2025 WALMART INC.

By: Julie Clark
Title: Attorney

Dated: September 12, 2025 Terawatt Infrastructure Inc.

By: Jason Berry
Title: Vice President, Energy

Dated: September 12, 2025 EVgo SERVICES LLC

By: Sara Rafalson
Title: Executive Vice President, External Affairs

Dated: September 12, 2025 SMALL BUSINESS UTILITY ADVOCATES

By: Britt Marra
Title: Executive Director

Dated: September 12, 2025 VEHICLE GRID INTEGRATION COUNCIL.

By: Zach Woogen
Title: Executive Director

Dated: September 12, 2025 WALMART INC.

/s/ Julie Clark
By: Julie Clark
Title: Attorney

Dated: September 12, 2025 Terawatt Infrastructure Inc.

/s/ Jason Berry
By: Jason Berry
Title: Vice President, Energy

Dated: September 12, 2025 EVgo SERVICES LLC

/s/ Sara Rafalson
By: Sara Rafalson
Title: Executive Vice President, External Affairs

Appendix A

Comparison of Party Positions On EV Rate Group Rate Design Issues and Settlement

Comparison of Positions
EV Rate Design Issues

Issue	SCE	Cal Advocates	CALSTART	EVgo	Walmart	SEIA	SBUA	Electrify America	2025 GRC Settled Position
TOU-EV-7	• Proposed that Schedule TOU-EV-7-Option-E remain an energy-only option for separately metered commercial EV charging, with Option-D available as an opt-in rate for EV customers with higher utilization and energy throughput (w/demand charges)	• N/A	• N/A	• N/A	• N/A	• N/A	• TOU-EV-7 - Aligns w/SCE to increase customer charge. Also, EV rates should be standalone & revenue neutral.	• N/A	• For distribution, all Peak-capacity, Grid-capacity, and the balance of the customer charge revenues are recovered via volumetric TOU. For TOU-EV-7 Option D, a FRD charge is introduced to recover a portion of the Grid-related cost thereby reducing the volumetric TOU Energy charges by an equal cents-per-kWh offset • For generation, all capacity and energy related costs are recovered via volumetric TOU Energy charges across both the summer and winter periods.
TOU-EV-8	• Proposed to maintain current TOU-EV-9 rate design and revise the energy charges to reflect updated marginal costs and revenue allocations	• Supports SCE's proposal to delay demand charges for TOU-EV-8 & 9,as they believe that continued financial support is reasonable to the extent it does not create unreasonable cost shifts to other customers.	• Supports SCE's proposal to extend the energy only structure for TOU-EV-9 until 2030. However recommends a phase in from 2030-2035 based on a sliding scale based on load factor. Recommends adopting 5 graduations for load factors below 25%. • Notes that it may be worth considering time-varying recovery of trans costs for charging site w/low utilization rates.	• Supports delay in introducing demand charges. Note that long-term, stable CEV rates are needed as market matures. Instead of initiating demand charges in 2030, CPUC should review CEV rate design either via the TE OIR or an SCE focused stakeholder process. If CPUC does not do this, SCE should revisit the future design of CEV rates prior to 2030 in a SCE-focused stakeholder process designed to result in a proposal in the next GRC Ph2 or an RDW.	• Supports SCE's proposal to delay introduction of demand charges. Believes this will also help DCFC infrastructure investment.	• N/A	•	• Generally supports SCEs proposal. Has concerns that increased rates & delay to introduce demand charges will harm sites that typically have higher utilization & higher load factors. (Increases total utility bill costs) Recommends reassessment of rate increases to EV-8 & 9 rates.	• For distribution, all Peak-capacity and Grid-capacity costs are recovered via volumetric TOU Energy charges across both the summer and winter periods. The proportion of seasonal revenue recovery is held constant relative to the current (October 2024) TOU-EV-8 rate structure. • For generation, all capacity and energy related costs are recovered via marginal cost based volumetric TOU Energy charges

Issue	SCE	Cal Advocates	CALSTART	EVgo	Walmart	SEIA	SBUA	Electrify America	2025 GRC Settled Position
									across both the summer and winter periods.
TOU-EV-9	• Proposed to maintain current TOU-EV-9 rate design and revise the energy charges to reflect updated marginal costs and revenue allocations	• Supports SCE's proposal to delay demand charges for TOU-EV-8 & 9,as they believe that continued financial support is reasonable to the extent it does not create unreasonable cost shifts to other customers.	• Supports SCE's proposal to extend the energy only structure for TOU-EV-9 until 2030. However recommends a phase in from 2030-2035 based on a sliding scale based on load factor. Recommends adopting 5 graduations for load factors below 25%. • Notes that it may be worth considering time-varying recovery of trans costs for charging site w/low utilization rates.	• Supports delay in introducing demand charges. Note that long-term, stable CEV rates are needed as market matures. Instead of initiating demand charges in 2030, CPUC should review CEV rate design either via the TE OIR or an SCE focused stakeholder process. If CPUC does not do this, SCE should revisit the future design of CEV rates prior to 2030 in a SCE-focused stakeholder process designed to result in a proposal in the next GRC Ph2 or an RDW.	• Supports SCE's proposal to delay introduction of demand charges. Believes this will also help DCFC infrastructure investment.	• N/A	•	• Generally supports SCEs proposal. Has concerns that increased rates & delay to introduce demand charges will harm sites that typically have higher utilization & higher load factors. (Increases total utility bill costs) Recommends reassessment of rate increases to EV-8 & 9 rates.	• For TOU-EV-9-SEC, PRI, and SUB distribution, Peak-capacity and Grid-related costs are recovered via volumetric TOU Energy charges across both the summer and winter periods. The seasonal revenue proportion is based on the marginal cost proportion of summer and winter revenues • For TOU-EV-9-SEC, PRI and SUB generation, all capacity and energy related costs are recovered via marginal cost based volumetric TOU Energy charges across both the summer and winter periods.
Option H	• SCE submitted a fully analyzed proposal for an Option S-like tariff.	• N/A	• N/A	• N/A	• N/A	• Supports adoption of this rate option, however, has concerns about SCE's analysis as it relates to FRD charges. Believes design should be based off Option E rate, then at least 80% of NCDCs for dist. cost should be converted to a fairly coincident pk demand charge.	•	• N/A	• Parties agreed to implementing an Option S rate for TOU-GS-2, TOU-GS-3, and TOU-8-SEC and made available to EV customers and customers with BTM storage with specific eligibility requirements. • Rate Design: For distribution, the rate structure introduces a Daily Peak-TRD charge to capture a portion of the Peak-capacity and Grid-related costs, and

Issue	SCE	Cal Advocates	CALSTART	EVgo	Walmart	SEIA	SBUA	Electrify America	2025 GRC Settled Position
									an FRD exclusion window where the FRD changes do not apply from 8 a.m. to 1 p.m. The remainder of the Option E FRD revenues is then designed for recovery in the Daily Peak-TRD charge. The residual portion of design demand revenues are recovered via volumetric TOU Energy charges that are set based on the TOU ratios of the respective class Option E rates and calculated to maintain revenue neutrality in each season • For generation, the design is identical Option E rate design where the recovery of energy and capacity revenues is via a TRD Charge set at twenty-five percent (25%) of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges
Zero Emissions Reporting	• SCE proposed to discontinue this reporting obligation	• Rejects SCE's proposal to remove this reporting requirement since it is premature to stop it since reporting would provide valuable insights on customer preferences & perceptions of rate options.	• N/A	• N/A	• N/A	• N/A	•	• N/A	• Settling Parties agree to modify the reporting requirements to provide enrollment number details specific to customer migrations from EV rates to Option E rates.

Appendix B

Illustrative EV Rate Group Rates

Table 1: Illustrative Rates TOU-EV-7 Option-E

	TOU-GS-1 EV-7 Option E									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$9.25			$9.25		$10.79			$10.79
On-kWh	0.01404	0.22740	0.33229	0.03615	$0.60988	0.01404	0.24461	0.35771	0.03615	$0.65252
Mid-kWh	0.01404	0.22740	0.11795	0.03615	$0.39554	0.01404	0.22200	0.11866	0.03615	$0.39085
Off-kWh	0.01404	0.09460	0.09692	0.03615	$0.24171	0.01404	0.11561	0.09214	0.03615	$0.25794
Max-kW										
Winter										
Customer Charge		$9.25			$9.25		$10.79			$10.79
On-kWh										
Mid-kWh	0.01404	0.22740	0.17901	0.03615	$0.45660	0.01404	0.08493	0.17477	0.03615	$0.30989
Off-kWh	0.01404	0.09460	0.11403	0.03615	$0.25882	0.01404	0.07920	0.10692	0.03615	$0.23631
SOff-kWh	0.01404	0.03249	0.05220	0.03615	$0.13488	0.01404	0.08849	0.04726	0.03615	$0.18594
Max-kW										
Three Phase Adder		$1.40			$1.40		$3.59			$3.59
EV Submeter Credit		($3.56)			($3.56)		($1.71)			($1.71)

Table 2: Illustrative Rates TOU-EV-7 Option-D

	TOU-GS-1 EV-7 Option D									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$9.25			$9.25		$10.79			$10.79
On-kWh	0.01404	0.21820	0.33229	0.03615	$0.60068	0.01404	0.23997	0.35771	0.03615	$0.64787
Mid-kWh	0.01404	0.21820	0.11795	0.03615	$0.38634	0.01404	0.21736	0.11866	0.03615	$0.38620
Off-kWh	0.01404	0.09078	0.09692	0.03615	$0.23789	0.01404	0.11096	0.09214	0.03615	$0.25329
Max-kW		0.94			$0.94		0.96			$0.96
Winter										
Customer Charge		$9.25			$9.25		$10.79			$10.79
On-kWh										
Mid-kWh	0.01404	0.21820	0.17901	0.03615	$0.44740	0.01404	0.08028	0.17477	0.03615	$0.30525
Off-kWh	0.01404	0.09078	0.11403	0.03615	$0.25500	0.01404	0.07455	0.10692	0.03615	$0.23167
SOff-kWh	0.01404	0.03117	0.05220	0.03615	$0.13356	0.01404	0.08384	0.04726	0.03615	$0.18129
Max-kW		0.94			$0.94		0.96			$0.96
Three Phase Adder		$1.40			$1.40		$3.59			$3.59
EV Submeter Credit		($3.56)			($3.56)		($1.71)			($1.71)

Table3: Illustrative Rates TOU-EV-8

	TOU-GS-2 EV-8									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$239.34			$239.34		$232.74			$232.74
On-kWh	0.01281	0.24131	0.36749	0.03653	$0.65814	0.01281	0.33557	0.34893	0.03653	$0.73383
Mid-kWh	0.01281	0.24131	0.10436	0.03653	$0.39501	0.01281	0.20780	0.11528	0.03653	$0.37242
Off-kWh	0.01281	0.09640	0.08073	0.03653	$0.22647	0.01281	0.06403	0.09002	0.03653	$0.20339
Winter										
Customer Charge		$239.34			$239.34		$232.74			$232.74
On-kWh										
Mid-kWh	0.01281	0.24131	0.15037	0.03653	$0.44102	0.01281	0.22881	0.16511	0.03653	$0.44326
Off-kWh	0.01281	0.09640	0.09488	0.03653	$0.24062	0.01281	0.07761	0.10451	0.03653	$0.23146
SOff-kWh	0.01281	0.02962	0.04081	0.03653	$0.11977	0.01281	0.03325	0.04620	0.03653	$0.12879
Single Phase Credit		(8.29)			($8.29)		(72.21)			($72.21)
EV Submeter Credit		(37.80)			($37.80)		(14.58)			($14.58)

Table 4: Illustrative Rates TOU-EV-9-SEC

	TOU-8-SEC EV-9									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$460.86			$460.86		$1,113.65			$1,113.65
On-kWh	0.01127	0.20478	0.28165	0.03370	$0.53140	0.01127	0.34937	0.30845	0.03372	$0.70281
Mid-kWh	0.01127	0.20478	0.09544	0.03370	$0.34519	0.01127	0.34937	0.08390	0.03372	$0.47826
Off-kWh	0.01127	0.06938	0.07411	0.03370	$0.18846	0.01127	0.05522	0.07150	0.03372	$0.17171
Winter										
Customer Charge		$460.86			$460.86		$1,113.65			$1,113.65
On-kWh										
Mid-kWh	0.01127	0.20478	0.13895	0.03370	$0.38870	0.01127	0.07998	0.16466	0.03372	$0.28963
Off-kWh	0.01127	0.06938	0.08509	0.03370	$0.19944	0.01127	0.07998	0.08104	0.03372	$0.20602
SOff-kWh	0.01127	0.02663	0.03941	0.03370	$0.11101	0.01127	0.03477	0.04448	0.03372	$0.12425

Table 5: Illustrative Rates TOU-EV-9-PRI

	TOU-8-PRI EV-9									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$475.29			$475.29		$313.25			$313.25
On-kWh	0.01013	0.17811	0.25832	0.03230	$0.47886	0.01013	0.29397	0.30879	0.03242	$0.64531
Mid-kWh	0.01013	0.17811	0.09157	0.03230	$0.31211	0.01013	0.29397	0.08089	0.03242	$0.41741
Off-kWh	0.01013	0.05663	0.07008	0.03230	$0.16914	0.01013	0.05054	0.06742	0.03242	$0.16050
Winter										
Customer Charge		$475.29			$475.29		$313.25			$313.25
On-kWh										
Mid-kWh	0.01013	0.17811	0.13844	0.03230	$0.35898	0.01013	0.07019	0.15989	0.03242	$0.27263
Off-kWh	0.01013	0.05663	0.08020	0.03230	$0.17926	0.01013	0.07019	0.07678	0.03242	$0.18952
SOff-kWh	0.01013	0.02368	0.03788	0.03230	$0.10399	0.01013	0.03052	0.04214	0.03242	$0.11521

Table 6: Illustrative Rates TOU-EV-9-SUB

	TOU-8-SUB EV-9									
	Current (October 2024)					Proposed				
	Trans	Distrb	Gen	Other	Total	Trans	Distrb	Gen	Other	Total
Summer										
Customer Charge		$4,951.05			$4,951.05		$8,512.50			$8,512.50
On-kWh	0.00895	0.05828	0.25163	0.02696	$0.34582	0.00895	0.09760	0.25359	0.02955	$0.38968
Mid-kWh	0.00895	0.05828	0.08606	0.02696	$0.18025	0.00895	0.09760	0.06975	0.02955	$0.20585
Off-kWh	0.00895	0.01211	0.06525	0.02696	$0.11327	0.00895	0.00510	0.05798	0.02955	$0.10158
Winter										
Customer Charge		$4,951.05			$4,951.05		$8,512.50			$8,512.50
On-kWh										
Mid-kWh	0.00895	0.05828	0.12264	0.02696	$0.21683	0.00895	0.01365	0.14025	0.02955	$0.19240
Off-kWh	0.00895	0.01211	0.07429	0.02696	$0.12231	0.00895	0.01365	0.06678	0.02955	$0.11893
SOff-kWh	0.00895	0.00288	0.03554	0.02696	$0.07433	0.00895	0.00364	0.03664	0.02955	$0.07879

Table 7: Illustrative Rates TOU-GS-2 Option S

	TOU-GS-2 Option S				
	Proposed				
	Trans	Distrb	Gen	Other	Total
Summer					
Customer Charge		$232.74			$232.74
On-kWh	(0.00003)	0.33373	0.30587	0.03624	$0.67581
Mid-kWh	(0.00003)	0.31008	0.11189	0.03624	$0.45818
Off-kWh	(0.00003)	0.09703	0.08685	0.03624	$0.22009
SOff-kWh					
Daily On-kW		0.36			$0.36
On-kW			3.45		$3.45
Mid-kW					
Off-kW					
SOff-kW					
Max-kW	3.80	3.71			$7.51
Winter					
Customer Charge		$232.74			$232.74
On-kWh					
Mid-kWh	(0.00003)	0.02500	0.14870	0.03624	$0.20991
Off-kWh	(0.00003)	0.01479	0.10434	0.03624	$0.15534
SOff-kWh	(0.00003)	0.03045	0.04613	0.03624	$0.11279
On-kW					
Daily Mid-kW		0.41			$0.41
Mid-kW			1.19		$1.19
Off-kW					
SOff-kW					
Max-kW	3.80	3.71			$7.51

Table8: Illustrative Rates TOU-GS-3 Option S

	TOU-GS-3 Option S				
	Proposed				
	Trans	Distrb	Gen	Other	Total
Summer					
Customer Charge		$1,140.50			$1,140.50
On-kWh	(0.00004)	0.31591	0.28430	0.03457	$0.63475
Mid-kWh	(0.00004)	0.30295	0.08313	0.03457	$0.42061
Off-kWh	(0.00004)	0.08534	0.06733	0.03457	$0.18720
SOff-kWh					
Daily On-kW		0.34			$0.34
On-kW			4.46		$4.46
Mid-kW					
Off-kW					
SOff-kW					
Max-kW	4.23	4.28			$8.51
Winter					
Customer Charge		$1,140.50			$1,140.50
On-kWh					
Mid-kWh	(0.00004)	0.02316	0.13835	0.03457	$0.19604
Off-kWh	(0.00004)	0.01346	0.08076	0.03457	$0.12875
SOff-kWh	(0.00004)	0.02823	0.04438	0.03457	$0.10714
On-kW					
Daily Mid-kW		0.37			$0.37
Mid-kW			1.68		$1.68
Off-kW					
SOff-kW					
Max-kW	4.23	4.28			$8.51

Table 9: Illustrative Rates TOU-8-SEC Option S

	TOU-8-SEC Option S				
	Proposed				
	Trans	Distrb	Gen	Other	Total
Summer					
Customer Charge		$1,113.65			$1,113.65
On-kWh	(0.00004)	0.30677	0.26417	0.03372	$0.60462
Mid-kWh	(0.00004)	0.28858	0.08384	0.03372	$0.40611
Off-kWh	(0.00004)	0.07765	0.06760	0.03372	$0.17893
SOff-kWh					
Daily On-kW		0.31			$0.31
On-kW			4.48		$4.48
Mid-kW					
Off-kW					
SOff-kW					
Max-kW	4.40	4.13			$8.53
Winter					
Customer Charge		$1,113.65			$1,113.65
On-kWh					
Mid-kWh	(0.00004)	0.03061	0.14242	0.03372	$0.20672
Off-kWh	(0.00004)	0.01759	0.08110	0.03372	$0.13237
SOff-kWh	(0.00004)	0.03767	0.04451	0.03372	$0.11586
On-kW					
Daily Mid-kW		0.33			$0.33
Mid-kW			2.00		$2.00
Off-kW					
SOff-kW					
Max-kW	4.40	4.13			$8.53